STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 97-596

November 24, 1999

PUBLIC UTILITIES COMMISSION
Investigation of Stranded Cost Recovery,
Transmission and Distribution Utility
Revenue Requirements, and Rate Design of
Bangor Hydro-Electric Company

ORDER

WELCH, Chairman; NUGENT and DIAMOND, Commissioners

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I. EXECUTIVE SUMMARY

We establish the principles and methodology by which the Commission will set Bangor Hydro-Electric Company's T&D revenue requirement for service beginning March 1, 2000. In its Reply Brief, BHE requests a revenue requirement of $111,352,541, composed of $71,316,686 for T&D services and $40,035,855 for stranded costs. Based upon our findings of a proper return on equity of 11.0%, we adopt adjustments that will reduce BHE's T&D portion of its revenue requirement by approximately $3.5 million, as shown in Attachment 1. This number is approximate because final calculations cannot be made until a Phase II update. Only then will the results of the QF auction be known, so that proper amortization periods can be chosen and that stranded costs can be calculated. We do not estimate the T&D stranded cost portion of the revenue requirement because any estimate will vary greatly depending on the QF auction results and amortizations of the available value for the generation asset auction.

We also establish principles and methodologies for the proper rate design of T&D rates, including standby rates. Standard offer prices must be determined before we can actually design rates in the Phase II update.

II. INTRODUCTION

In this case, the Commission implements the legislative directive in the Electric Restructuring Act (35-A M.R.S.A. §§ 3201-3217) to establish Bangor Hydro-Electric Company's rates for the start of retail choice on March 1, 2000.[1] On that date, electric generation retail service becomes subject to competition rather than rate regulation. The delivery of electricity will remain regulated as a utility service.

The Restructuring Act required each electric utility to divest generation-related assets and businesses. The Commission must conduct adjudicatory proceedings to determine for each utility the generation costs stranded by restructuring. In the same proceeding, the Commission must determine the revenue requirement for the remaining transmission and distribution (T&D) utility and the stranded cost charges that will be collected through the T&D rates. 35-A M.R.S.A. § 3208(8). These adjudicatory proceedings must be concluded by December 1, 1999. *Id.*

The Commission must also design rates to recover the revenue requirement for T&D costs, stranded costs, and any other costs required by the Act to be recovered through T&D rates. The Act also requires the Commission to design rates for backup or standby service. These rate design adjudicatory proceedings must be completed by December 1, 1999. 35-A M.R.S.A. § 3209.

This fundamental change in the operations of BHE makes setting T&D only rates particularly difficult because BHE operated in the test year as a vertically integrated electric utility. Still, we must project the costs and revenue for the new "wires" company during its initial year as a power deliverer. As we cannot base our decisions on the actual operation of a T&D utility, we must, to a greater extent than usual, rely on evidence drawn from analogous circumstances and on our judgment.

In the introductory comments to its brief, BHE asserts that T&D utilities must enter restructuring in a strong financial position. In BHE's view, if rates set as part of this proceeding do not improve shareholder returns compared to these achieved by Maine's electric utilities over the last five years, restructuring will not be well received by the financial community and consequently may fail. BHE concludes that "now is not the time to err on the side of lower rates when making difficult judgment calls."

The OPA views BHE's approach to this case as an attempt to seek the highest reasonable level of T&D revenue requirement. The OPA criticizes BHE's position, that in OPA's view, requests preference for shareholder rather than ratepayer concerns. OPA also criticizes BHE's request for reconciliation of certain categories for expenses, which in the OPA's view, amount to an insistence of guaranteed cost recovery. OPA asserts that 1999 earnings for Maine electric utilities appear more robust and that the poor shareholder returns in the last five years for BHE are offset by the fact that BHE has the highest electric rates in Maine.

[1] The Procedural History of this investigation is contained in Appendix A.

While we agree that ratemaking for the restructured electric industry requires greater reliance on judgment, to the extent that BHE seeks a decision setting forth a principle that somehow shareholders should be favored over ratepayers, we do not grant BHE's request. We do not view restructuring as requiring any change in our approach to balance both shareholder and ratepayer interests. Indeed, we believe the Restructuring Act itself envisions such a result. 35-A M.R.S.A. § 3208(5). Moreover, the recent poor financial returns earned by BHE shareholders were caused by Maine Yankee operational difficulties and shutdown and the Company's decision to voluntarily "stay-out" as part of pricing flexibility program.[2]

Maine Yankee was, of course, a generation asset. One of the reasons for adopting electric restructuring is to insulate utility ratepayers from the generation investment risks. Indeed, all of the financial and ratemaking crises in the last 20 years for BHE have involved generation investments, namely, the Seabrook and Maine Yankee nuclear power plants, and its qualifying facility contracts. As utility shareholders will no longer be subject to the generation investment risk, there seems to be little justification for using the recent poor financial returns as a reason itself for adopting any of BHE's proposed ratemaking adjustments or higher T&D utility returns in general.

We see no need to depart from our usual ratemaking principles wherein we seek to balance shareholder and ratepayer interests. We will now apply those principles to establish the T&D revenue requirement and to decide stranded cost recovery methodologies. Stranded costs cannot be finally calculated until the results of the QF output auction are known. Rate design also cannot be implemented until standard offer prices are known. Accordingly, actual rates must await further information. As noted in Section V of this Order, we will conduct an update proceeding to process the QF output and standard offer information when available.

[2] The financial predicament created by Maine Yankee difficulties was discussed extensively in our order in BHE's last rate case, *Bangor Hydro-Electric Company, Proposed Increase in Rates,* Docket No. 97-116, Order (February 9, 1998) (hereinafter *"97-116."* The rate consequences of BHE's financial difficulty caused us to replace the informal stay out "rate plan" with a formal rate cap incentive plan.

III. REVENUE REQUIREMENTS

A. Cost Separations

1. Positions Before the Commission

In a case with at least its fair share of apparent disagreements, there appears to be broad agreement that separating the costs of an integrated utility such as Bangor Hydro in the test year is a difficult task. Given this difficulty, the area of disagreement over cost separations are remarkably few, though still controversial. In fact, the only area of disagreement is over the appropriate share of Administrative and General (A&G) expenses that should appropriately be allocated to the Transmission and Distribution (T&D) function.

In its original filing in July 1998, BHE proposed that A&G expenses, as well as A&G plant should be allocated among T&D, generation, and non-core activities in proportion to the wages allocated to each function. This resulted in 88.12% of the costs being attributed to T&D with 10.73% going to generation and 1.15% going to non-core. Initially, BHE considered this allocation appropriate for both plant investment and expense. Six months later, in a letter dated December 28, 1998, BHE changed its proposed allocation of A&G costs in three ways:

1. It eliminated the allocation of regulatory assessments to generation,

2. It eliminated any allocation of A&G plant investment to generation, and

3. It reduced by one-half the allocation of A&G expenses to the generation function.

The Bench Analysis accepted the first two changes. The OPA accepted the first, but did not agree that no A&G plant should be allocated to generation. The last item, A&G expenses, became the subject of a rather vigorous debate.

The Bench Analysis, issued June 10, 1999, noted that the record evidence at that time was very thin and provided little justification for BHE's proposed change other than its statement that having reviewed its ongoing needs with respect to A&G it believed it would "not be able to reduce these expenses by the amount" it had previously recommended. The Bench Analysis recommended that that BHE's original allocation be used for two categories of A&G expense, Office Supplies and Outside Services, on the theory that these types of expenses could be relatively quickly adjusted and proposed assigning 75% of BHE's original proposal for the remaining categories, rather than 50% as BHE suggested. In its Brief, the OPA accepted the treatment proposed in the Bench analysis. BHE did not.

2. Decision and Analysis

BHE observed in its Brief:

> The Bench Analysis criticizes the Company for offering 'no explanation why a reduction of 50% as opposed to, say a reduction of 10% or 90% is reasonable.' The Staff then turned around and proposed an allocation which, with two minor exceptions, simply splits the difference between Bangor Hydro's original allocation and its revised allocation. The staff's original allocation is at least as arbitrary as the Company's revised allocation.

BHE Brief at 10.

BHE is correct to note that both proposals are arbitrary. In fact, the only non-arbitrary evidence in the record is BHE's initial testimony which it later rejected. It is possible that, had BHE initially used a methodology similar to its final position, the Bench and or the OPA would have arranged to have an outside study of the issue prepared. However, by the time BHE filed its final position, an outside study was not practical and, as a result, the record on the issue is relatively weak.

BHE makes several criticisms of the Bench Analysis. It states that "The first and most glaring error in the Staff's analysis is that the Staff apparently ignored the direct allocation of A&G costs to generation." The Bench Analysis, however, accepted BHE's proposed direct allocations of A&G costs. BHE's criticism here is founded on the assertion that "the more costs that are directly allocated, the smaller the percentage of costs that should be indirectly allocated." It is not clear why this statement should be true. BHE appears to say that if most costs are allocated, it makes sense to allocate a high proportion to generation, but if a majority of costs can be directly assigned then a large share of the remaining costs should be allocated to transmission and distribution. In the absence of an explanation as to why this would occur, we cannot place any weight upon it.

BHE's next assertion is that the Advisory Staff's approach to A&G costs is not only inconsistent with the reasonability check Dr. Austin discussed during the hearing, but is also "the strongest indictment of the Staff's adjustment." BHE Brief at 11. In the transcript cited by BHE, Dr. Austin stated that BHE had total A&G costs of about $11 million, that for purposes of the Accounting Order,[3] the Commission used an

[3] On September 8, 1999, the Commission issued an Accounting Order in this docket which granted in part the Company's request to defer certain restructuring-related expenses.

A&G adder of approximately 17%,[4] and found that one-half of these overheads should be considered incremental for purposes of the Accounting Order. This suggests an overall A&G cost of roughly $935,000 ($11 million times 17% divided by 2). As BHE points out in its Brief, it is recommending a figure of $791,255 while the Bench analysis figure is $1,039,940. The reasonability test offered by Staff tends to indicate that both the Staff and the Company's proposals are within the range of reason.

BHE's next point is that "the Staff's allocation was particularly out of line when one considers the number of employees who are no longer employed by the Company as a result of the sale of BHE's generation assets." BHE Brief at 11. If BHE were arguing that we should use labor as a reasonable allocator, this argument might be sensible. However, BHE proposes to allocate one-half the costs which would result from a labor allocation of A&G, while the Bench Analysis is proposing to use 75% of the labor allocator. The Bench Analysis does not attempt to allocate costs more than proportionally to labor as claimed by BHE.

Having reviewed the evidence, we agree with the Bench Analysis on cost separations. BHE argues that this issue "involves a significant amount of judgment and experience," but fails to convince us that its judgment is fully reliable on cost separations. We agree with Advisory Staff that as a matter of logic certain types of costs can be adjusted more quickly than others and this should be taken into account in our cost separations decisions.

Finally, the OPA argues that a portion of BHE's A&G plant should be attributed to generation, more specifically 75% of the amount that BHE allocated in its initial study on the topic. While the OPA's position may have some merit, we decline to accept it here. It is more difficult to adjust plant investment to changing circumstances and for that reason, we declined to make such an adjustment when a similar issue was raised for Central Maine Power. *Public Utilities Commission, Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements and Rate Design,* Docket No. 97-580, Order at 13, (March 19, 1999) (hereinafter *"97-580."*) We are not persuaded that we should change that approach here.

B. Test Year

1. Hermon Substation

The Company proposed an adjustment to remove from test year revenue $350,000 received from Central Maine Power Company (CMP) related to the 5-year distribution agreement associated with the Herman Substation. As indicated in the agreement between the two utilities, BHE received a one-time payment of $646,466 from CMP in 1997. It allocated $350,000 of this amount to transmission revenue and

[4] The 17% adder was later updated to 15.74%. Using this figure would not result in a significant change.

considered the remainder to be a contribution in aid of construction. The agreement also specified that CMP would pay BHE $16,150 per month ($193,800 annually).

There appears to be no disagreement as to the facts. The disagreement is over how this revenue should be treated for ratemaking purposes. BHE argues that the $350,000 in revenue should simply be removed from the test year. The Bench Analysis proposed that the revenue be normalized over the 5-year term of the agreement so that 1/5, or $70,000, should be reflected in test year revenues.

According to the Bench Analysis, the $350,000 was intended to compensate BHE for services it was providing during the 5-year term of the contract, and BHE ratepayers should pay only the net costs of providing service, after reflecting revenues received from other sources. The normalization approach was driven, in part, by a concern that utilities have an incentive to structure contracts and revenues so as to avoid being credited to ratepayers.

We decline to accept the Bench Analysis on this point. In general, we should disturb accounting entries in the test year, which were made in the ordinary course of business, only where clear reasons (such as extraordinary size or important policy concerns) exist.

In this case, while BHE and CMP structured the contract to provide a $350,000 upfront payment, BHE also receives $193,800 annually from CMP. If this were truly a case in which BHE were trying to capture the full revenue for stockholders, it would presumably also have structured these payments to be part of the original lump sum. That said, we would also point out that Bench's concern about the timing of receipts is not without merit. Under a different factual background, we might decide that a normalization treatment is warranted.

2. Adjustment No. 25 -- Transmission Revenues

a. Positions Before the Commission

BHE proposes to remove test year transmission revenue of $436,327. BHE received this revenue during the test year by wheeling power from the Indeck and Worcester Peat plants across its service territory. BHE argues that the plants operated in the test year because of the outage of Maine Yankee and other large New England generating facilities and that under more normal conditions the plants would not operate and, therefore, no wheeling revenue would be received.

BHE further argues that the possibility it would receive transmission wheeling revenue from any other source during the rate year is also unlikely. BHE notes that energy sales to customers within its service territory would not produce wheeling revenue. In addition, any revenue from power wheeled across or out of its service territory would be FERC-jurisdictional and, BHE asserts, would have no bearing on the revenue requirement set in this proceeding. BHE acknowledges that, in theory, there could be transmission revenue from power wheeled across its distribution system that would be state-jurisdictional, although BHE argues that any such distribution wheeling is unlikely to occur.

The OPA argues that an assumption of no wheeling revenue in the rate year is simply not credible. The OPA points out that any generator in BHE's territory, such as PPL Global, must pay to wheel across BHE's local transmission system. The OPA urges the Commission to reject BHE's removal of all transmission wheeling revenues from the test year.

b. Analysis and Conclusion

There are two separate issues that must be considered with respect to this adjustment. The first issue is the likely level of transmission wheeling revenue in the rate year. The second issue is whether or not we should consider transmission revenue at all in setting rates given FERC's assertion of jurisdiction over transmission rates. We address each of these issues separately below.

Regarding the likely level of wheeling revenue, we do not agree with BHE that zero is the proper amount to assume for ratemaking purposes. BHE correctly notes that it will not receive wheeling revenue from power sales to customers in its service territory. However, it is far from clear that all of the generating facilities located within BHE's service territory will serve BHE customers. With the expansion of retail access in New England, generators will have market opportunities in the rate year that did not exist in the test year. The power produced by the PPL facilities, as well as that provided by BHE's purchased power entitlements, such as PERC and West Enfield, may be sold to retail customers in other parts of Maine, or in other New England states. Another possibility is that the power may be sold through a wholesale contract or into the regional spot market. These transactions would require the generating facilities to wheel their power across BHE's local transmission system to the Pool Transmission Facilities (PTF) resulting in transmission revenue for BHE. Furthermore, there will be increased market opportunities for the Indeck and Downeast Peat plants in the rate year as compared to the test year in both retail and wholesale markets. For instance, market prices resembling the clearing prices in the ISO-NE spot markets last summer may alone provide sufficient economic inducement for Indeck and Downeast Peat to return to operation.

BHE argued that, because transmission wheeling revenues are FERC-jurisdictional they are not relevant to the revenue requirement being set in this case. We do not agree. The Commission is establishing BHE's total revenue requirement and setting the total retail rates customers will pay as of March 1, 2000 for T&D service. BHE has not proposed to fully separate the transmission component from this revenue requirement. To do so would require cost separation analysis such as that being done in this case for generation. The Commission should, therefore, set the transmission-related portions of BHE's revenue requirement using the same rate-setting methodologies it applies to other components of the T&D revenue requirement.

Specifically, the Commission should use the same historic test period with adjustments for known and measurable changes.

As discussed above, the record in this proceeding does not support BHE's position that it will receive no transmission wheeling revenue in the rate year. Since there is inadequate evidence to support a known and measurable change to the test year, we conclude that the test year revenue amount of $436,327 should be used.[5]

3. Line Clearance

In its Brief, BHE states that there is "a significant disagreement over tree trimming costs . . . About the only thing on which the Staff and the Company agree is that the Company incurred $1,473,937 of line clearance expense in the test year and that the Company has recently moved to a 6-year tree trimming cycle." BHE Brief at 21. The difference between the two positions is that BHE would increase tree trimming expenses by approximately $357, 000 to $1,831,000, while the Bench Analysis recommends a somewhat smaller increase of $246,000.

The disagreement apparently stems from the Bench Analysis statement that "Black and Dawes request that test year line clearance expense be increased by $357,063 from $1,473,937 to $1,831,000. They state that this would allow BHE to move from a 7-year tree trimming cycle to a 6-year cycle and should help reduce power outages, improve power quality, and increase customer satisfaction."

Carroll Lee, on behalf of BHE, later took a different position stating that the 1997 test year did not, in fact, reflect a 7-year cycle as Black and Dawes had testified but rather was for a longer cycle. Mr. Lee stated that BHE has budgeted for $1,831,000 for 1999 but does not suggest whether that expenditure level supports a 6-year cycle or some shorter period. The Bench Analysis, based upon the Black/Dawes Testimony, concluded that in order to move from a 7- to a 6-year cycle the cost should be increased by one-sixth, which was the basis for this recommendation.

At this point, the record on this issue is far from clear. We will, however, accept BHE's adjustment. BHE asserts that it is spending at the budgeted level of $1,831,000. We will accept the decision to increase spending on this line item and assume that it will continue to spend at these levels in the rate year and that the increased expense will improve the quality of service. Moreover, in light of our experience with the 1998 ice storm, we do not want to discourage BHE from adopting a more aggressive tree trimming policy.

[5] We anticipate that, in light of the broad areas of uncertainty here, we would remove this revenue from our calculation of T&D revenue requirements in this case upon a ratemaking proposal from BHE that would hold ratepayers harmless from the beginning of the rate effective period until such time that a distribution only revenue requirement is established by the Commission.

4. Hydro-Quebec Settlement

During the first quarter of 1999, Bangor Hydro received $802,000 as a result of a settlement by New England Power Pool (NEPOOL) of a contact dispute with Hydro Quebec (HQ). The major dispute between the NEPOOL members and HQ related to calculation of the price paid under the Firm Energy Contract. The price is set by formula in the contract, to be a percentage of the Annual Weighted Fossil Energy Cost in New England on a marginal cost basis. Fossil energy excludes electricity for coal, oil and gas. The major dispute related to whether fixed pipeline charges should be included in the marginal cost of gas fuel in the formula. HQ contended the fixed charges should be included, and beginning in 1996, NEPOOL members began paying the higher charges because of the inclusion of the fixed charges. The NEPOOL members disputed the inclusion of the higher charges, and eventually they prevailed and received a refund. Bangor Hydro's share of the net refund was $802,000. The OPA recommends that the Commission defer the $802,000 settlement for ratemaking purposes and amortize the amount over a 4-year period.

The OPA asserts that because the costs of BHE's Hydro Quebec Phase II entitlement were included in BHE's rates, the reduction in those costs represented by the contract settlement should be passed on to ratepayers. Moreover, the OPA argues that equity requires BHE customers to benefit from the contract settlement because the Company includes the cost of the Hydro Quebec entitlement as a stranded cost to be collected from T&D ratepayers.

We do not agree with OPA's adjustment. Although rates set in 1998 did reflect the higher HQ costs, the contract settlement occurred during the operation of BHE's rate plan. Other BHE expenses were no doubt different in 1999 from those reflected in rates set in 1998. The revenue received by BHE during 1999 from Hydro Quebec should be treated as part of the on-going operations of the utility, namely a reduction in power supply costs. Under the rate plan, rates were set by formula, not by increases or decreases in actual expenses. The OPA's proposed adjustment is contrary to the rate plan.

We are also not persuaded that recognition in rates of the contract settlement amount is proper based upon the fact that the Hydro Quebec contract entitlement will become part of BHE's stranded cost recovery. Past costs were overstated by an amount now represented by the contract settlement. Stranded costs will not be overstated because past operating costs were overstated. Presumably, future HQ costs will also no longer reflect the fixed pipeline charges in the price formula. In that sense, to the extent BHE still pays HQ costs, stranded costs will be lower because of the contract settlement. Therefore, equity does not require BHE to reduce stranded costs by the amount of past overcharges. Equity might require a different result if NEPOOL members settled the HQ dispute by accepting full refunds for past costs, while also accepting that future prices could include the fixed charges in the formula. To the extent those future, higher operating costs were used to calculate stranded costs, equity might require the allocation of some of the settlement to mitigate stranded costs in the future.

5. Alternative Minimum Tax (AMT)

The OPA urges the Commission to remove the Company's AMT asset deferred tax balance from its T&D rate base for two reasons. One, the AMT balances are stranded costs not T&D assets. Two, the deferred asset will be reduced or eliminated if the sale of the generation assets is above book value in aggregate.

The Company has responded that it is indifferent to whether the AMT balance be shifted to stranded costs versus T&D rate base. It, however, disagrees with the removal from rate base entirely as suggested by the OPA. The Company has stated that under Section 56 of the Internal Revenue Code, the AMT credit could not be used to offset current taxes until after both the Net Operating Loss (NOL) carry forward and existing Investment Tax Credits (ITC) are considered.

There is no evidence showing the specific preference items that led to the deferred AMT asset and therefore, it cannot be stated unequivocally that the AMT asset should be classified as a stranded cost. However, since the Company shows no strong objection to classifying the AMT deferred tax asset as a stranded cost instead of a T&D rate base item and we also do not see a difference in the resulting current rates, we will accept the OPA's adjustment to classify the deferred asset as a stranded cost.

The sale of the generation assets has taken place at above book value. King Exhibit K-TP-1 shows that although a portion of the deferred AMT asset will be used against 1999 current taxes, the full balance will not be utilized until the 2000 tax year. Given that the deferred tax asset will not be fully utilized prior to the close of the rate year, we will not accept the OPA's adjustment to remove the AMT Asset Deferred Taxes from rate base entirely.

6. Legal Expense

As part of the Commission's Accounting Order in this docket, we allowed the Company to defer for future recovery in rates its outside legal expenses incurred for this case. The Company estimated that these expenses would be $160,000. The Company has, as part of its revenue requirement case, also requested that $117,000 of outside related regulatory legal expenses be included in permanent rates based on 1997 test year expenses. In that decision, we noted that an accounting order should not provide the Company with the means of recovering for the same expense twice. We, therefore, stated that we would assess the Company's request to recover regulatory-related legal expenses in light of our decision to allow the Company to recover rate case legal expenses as part of its accounting order request. Accounting Order at 8 (Sept. 8, 1999).

In reviewing the Company's test year legal expenses, we note that $30,000 of the test year expenses were incurred for litigating the Company's temporary rate case. BHE's temporary rate case in 1997 was the first emergency rate case involving an investor-owned electric utility before this Commission in approximately the last 15 years. We view these legal expenses as extraordinary and similar to restructuring-related expenses for which we have already allowed BHE recovery. Such expenses should not be included in permanent rates. We will thus allow $87,000 (i.e., the test year level of $117,000 minus $30,000) in rates for outside regulatory legal expenses in this case.

In calculating the amount attributable to restructuring in 1999, some "normal" amount of legal expense should be subtracted from the outside legal expenses incurred during the period covered by the Accounting Order.[6] We could view as "normal" either the amount we allow into rates today (i.e., $87,000) or the amount that is currently included in rates pursuant to our Order in *97-116.* While the restructuring related legal expenses will actually be recovered subsequent to our setting of rates in this case, the expenses will be incurred during the time that *97-116* rates are in effect. We therefore believe that the amounts included in *97-116* rates better represent the "normal" expenses for the time period in question and will use that amount ($1,200) in calculating incremental restructuring related outside legal expenses.

C. Attrition

1. Overview

Traditional regulation in Maine, as in most states, sets rates by looking at the sales, costs, and rate base in a recent historical period, the test year. This approach is based upon the presumption that while all of these items might change between the test year and the period when the new rates will be in effect, these changes will be of similar proportion. For example, if sales, costs, and investment are all three percent higher during the rate effective period (the first year the new rates will be in effect) compared to the test year, then the utility would earn its allowed rate of return and ratepayers would be paying reasonable rates. An attrition study is a formal attempt to test that presumption. The analyst adopts forecasts for these three components and checks to see whether that test year balance will be maintained, given the adopted forecasts. This general discussion of attrition is important because it highlights the key difference between traditional test year analysis and an attrition study. In considering the test year, we look at actual accounting values, and adjust for known and measurable changes. But for the rate effective period, the concept of "known and measurable" must be jettisoned, to be replaced by the less certain world of forecasts. Attrition analysis is particularly difficult, and important, in this case because we are

[6] Under the terms of the Accounting Order the Company will submit for approval and collection in rates the restructuring expenses which we approved for recovery in the Accounting Order. As noted previously, the Company has estimated its outside restructuring legal expenses to be $160,000. We would view a request substantially above this projected amount quite skeptically and carefully look at the prudence of such expenditures.

relying on a relatively old test year, 1997, for rates which will take effect beginning in March 2000.

BHE's case includes an attrition study by Mr. Mathieu Poulin, which draws, in part, on the testimony of various other BHE witnesses. In the most recent update (July 28,1999) Mr. Poulin recommends an attrition adjustment of $3,964,065. BHE's attrition request is driven in large part by flat sales and revenue growth, ongoing capital spending which increases rate base and depreciation expense and by his assumptions concerning the trends of future O&M expenses.

Mr. Poulin's analysis of revenue growth is driven by two items. The first is that he assumes very modest growth in sales generally. This modest level of growth has not been challenged by the parties or by the Bench Analysis. The second reason for low revenue growth is the assumption, based on Mr. Jones's testimony, that the revenues from two large customers, Lincoln Pulp & Paper and HoltraCherm will be lower by $1,200,000 and $1,500,000, respectively. This lower revenue results from BHE's assertion that rates for these customer will need to be reduced. In effect, what Mr. Poulin is saying here is that the actual attrition amount is $1,264,065 ($3,964,065 less the $2,700,000 rate reduction for Lincoln Pulp & Paper and HoltraChem). The rate reduction for Lincoln Pulp & Paper and HoltraChem is discussed more fully in Sections III (C)(5) and III(E), below.

The Bench Analysis raised several issues regarding the attrition study, some of which apparently resulted in changes to BHE’s position. In particular, BHE adopted the Bench Analysis positions on uncollectible expense and property tax expense. In the course of the case, BHE has also adopted lower estimates of future plant investment than it had used initially. However, disagreements still remain surrounding the issues of the likely level of overheads associated with new construction, the proportion of construction expense associated with land purchases (which affects depreciation expense) and future operations and maintenance expense, including the issue of whether some improvement in productivity should be included in the forecast.

2. Revenue from Generation Suppliers

The OPA urges the Commission to reduce BHE’s revenue requirement to reflect the revenue it will receive in the rate year from competitive electricity providers (CEPs) for enrollment, metering, billing and collection services provided pursuant to Commission rules. The OPA states that this is appropriate because ratepayers will pay for the investments and operating costs necessary to provide these services. The OPA notes the Company’s adjustment to remove $566,750 from rate base to account for incremental billing capital expenditures, but argues that this does not fully account for the net effect of the revenues BHE will receive from CEPs. Thus, he recommends that his witnesses’ conservative estimate of $287,917 of CEP revenue be used in establishing the revenue requirement.

BHE responded that it has removed all projected revenue and all incremental expenditures (i.e. the $566,750 rate base adjustment) associated with CEP services from its revenue requirement calculations. BHE argues that this approach is appropriate because the amounts collected from CEPs are only intended to cover incremental expenses.

We do not accept the OPA's proposed adjustment. BHE is correct that that the amounts charged to CEPs are intended to cover the utility's incremental costs of providing the services. Therefore, BHE is also correct that, conceptually, projections of CEP revenue should not be accounted for as long as no incremental costs of providing CEP services are included in the revenue requirement. For this reason, we reject the proposal to include a projection of revenue from CEPs in BHE's attrition analysis. However, BHE must confirm that there are no costs in addition to the $566,750 in capital expenditures embedded in its revenue requirement calculation that were used (or will be used) in determining the amounts to be charged to CEPs.

3. Rate Base - Construction Overheads

In its attrition study, BHE assumed that construction overheads would amount to approximately 25% of direct construction for 1999, but that this figure would rise to approximately 30% for 2000 and 2001. The Bench Analysis recommended estimating overheads at 25% for all three years. The Bench Analysis recommendation, if adopted, would result in $12.31 million in 2000 and $10.44 million in 2001, rather than the BHE's estimates of $12.85 million and $10.85 million, respectively.

Both BHE and the Advisory Staff responded to an oral data request asking for the overhead percentages for 1997 and 1998, but interpreted the questions differently. The Advisory Staff reported that the 1997 and 1998 budgets used figures of 24.0% and 28.9%. BHE reported actual, rather than budget figures of 31.41% and 27.60%, for 1997 and 1998 and a budget of 23.76% for 1999. Since there are no budgets for 2000 and 2001 as yet, this appears to be the best information available. The average of the BHE figures for the three years is approximately 27.5%. We will adopt that figure for purposes of the attrition study.

4. Expenses

a. Depreciation Expense

The issue here is the proportion of future plant additions that is likely to be land purchases as opposed to structures and equipment. The issue is relevant because land is not depreciable so that the greater the proportion of land in the total construction budget, the lower depreciation expense will be.

In his attrition study, Mr. Poulin assumed that almost none of the future construction budget, 0.433%, would be expenditures for land. He developed this figure by beginning with the actual land expenditures for the 1997 test year, in which land comprised approximately 10.7% of expenditures, and eliminating certain 1997 construction projects as being unrepresentative of the future. Essentially, the Company eliminated almost all land expenditures from its attrition study. The Bench Analysis observed that the Mr. Poulin's land estimate was rather low, and suggested using the historical average for BHE of 2.859% as being a more likely to represent the future level of land expenditures. BHE, in its Brief now argues for a figure of 1.7% because this is the figure from BHE's 1999 budget and because it is "approximately halfway" between their prior estimate and the Bench Analysis.

For the years 1989 through 1998 the average land expenditure was 6.91%, and the single lowest figure (1990) was 1.99%. We believe that the Bench Analysis recommendation is, if anything, on the low side and adopt it for the attrition analysis.

b. Operations and Maintenance Expenses

In its attrition study, BHE increased a number of Operations and Maintenance expenses by expected future inflation. The OPA suggested that it would be reasonable to expect BHE to increase productivity between the 1997 rate year and the rate effective period, that is, the year beginning March 1, 2000. BHE asserts that, given such issues as Y2K preparedness and restructuring, it will be unable to do so. The Public Advocate, through its witness Mr. Kollen, believes that BHE should be able to achieve productivity savings and thus, should be able to hold its cost increases to a level of 1.2% below inflation. The Bench Analysis suggested not escalating four specific cost categories, amounting to $164,000, as an alternative to adopting a productivity adjustment. One reason for the Bench Analysis recommendation here was that, at the time that analysis was written, the Bench was also recommending rejecting a number of the restructuring cost deferrals which BHE was proposing. Had this approach been adopted by the Commission, base rates, as set in this proceeding would have had to fund these activities that are now being separately funded.

The OPA cites BHE's past performance and the testimony of its own witness, Mr. Kollen, to support its argument in favor of a 1.2% productivity improvement factor which, according to the OPA, would result in a reduction in rate year O&M expense of $574,263. Mr. Kollen testifies that the national average increase in productivity since 1997 has been 2.97%, suggesting that a 1.2% annual improvement is conservative.

We do not adopt the Bench Analysis here for two reasons. First, as that Analysis pointed out, one reason it declined to adopt a productivity offset was the assumption that BHE would not be allowed to defer many of the restructuring costs (see our Accounting Order of August 8, 1999). Second, the Bench Analysis sought to combine two issues, future escalation of expenses such as tree trimming and post retirement benefits (which would tend to increase BHE's rates) and the productivity offset (which would reduce those rates) arguing that it could resolve its uncertainty over two issues, by simply assuming that the two would offset. Instead, we accept BHE's position that some level of escalation for tree trimming and post-retirement benefits will occur and thus turn to the question of whether O&M costs should simply be escalated with inflation or whether a productivity offset is appropriate.

In BHE's alternative rate plan, we adopted a productivity offset of 1.2% based on our view that BHE could, and should, be able to improve the efficiency of its operations. BHE's Senior Vice President and Chief Operating Officer, Carroll Lee, testified that "overall O&M expenses remained at approximately the same level from 1993 to 1997 despite inflation (which averaged about 3% per year or 13% cumulative) and despite increases in sales of 8%. Overall efficiency thus increased by about 20% from 1993 to 1997." If BHE were able to attain similar efficiency improvement between 1997 and 2000, this would seem to imply a productivity offset of around 10% or 3% to 3.5% annually. A 20% improvement over 4 years equates to 15% over 3 years. BHE projects sales growth of a little less than 1% while inflation, according to Mr. Poulin's exhibit P-SR-7-1 (July 27, 1999) cumulatively will be about 3.5%, resulting in a net productivity improvement of just over 10%. After allowing for the effects of compounding, this implies an annual rate of improvement of 3.2%.

There is no evidence in the record that suggests that Y2K preparedness costs will be substantial, and, in any event, Y2K costs are likely to be incurred by many firms throughout the economy so these costs should be covered by overall inflation assumption being applied to BHE's costs. In CMP's case, we did consider the cost of serving new customers as a partial offset to productivity savings. In this case, however, BHE is projecting little revenue growth and has not presented evidence showing the marginal costs of customer growth.

There is some suggestion, however, that there will be some ongoing costs associated of restructuring although there is no analysis of the extent to which these costs are already included in the Company's attrition request. Because we wish to make some allowance for these restructuring costs, we will reduce the productivity offset from 1.2% to 1%. This is the same productivity offset which we adopted recently for CMP. *97-580* at 28-29. As shown in table 1, the affect here is to reduce the rate year O&M increase from $422,000 which BHE requests to $88,000.

5. <u>Non-Core Revenues</u>

a. <u>Space-Heat Adjustment</u>

(i) <u>Overview</u>

In November 1993, the Commission authorized BHE to offer a 9 ¢/kWh discount space-heat rate to its residential customers. However, in its Order allowing this program, the Commission specifically required that ratepayers not bear the risks associated with this program. *Bangor Hydro-Electric Company, Proposed Schedules to Provide for Residential Space Heating Service Rate and Residential Electric Thermal Storage Rate,* Docket No. 93-205, Order at 8 (MPUC

November 29, 1993). Further, the Order approving this rate mandated that it would terminate on October 31, 1995, and that BHE must provide customers with information regarding the temporary nature of these rates. *Id.* at 5.

In 1995, BHE sought, and the Commission approved, a 5¢/kWh residential discounted space-heat rate that superceded the 9¢/kWh rate. This rate was authorized to continue through September 30, 1998. In its Order approving this program, the Commission required that "to the extent possible financial risks be shifted from ratepayers to stockholders" by:

> [I]mputing for ratemaking purposes revenues to the Company in the amount that it would have collected at the otherwise available residential rate, assuming that BHE would have lost 4% of its heating load each year.

Bangor Hydro-Electric Company, Proposed Schedule to Provide for Residential Space Heating Price (94-125), Docket No. *95-701* and *Bangor Hydro-Electric Company, Proposed Schedule Revisions to Provide for Residential Space Heating Price-Permanent Load (AMP 94-125),* Docket No. 95-702, Order at 5 (MPUC July 21, 1995). The Commission noted also that, "the relatively short effective period provides additional protection both to the Company's financial condition and ratepayers long-term interests." *Id.* at 7. In an Order dated November 29, 1995, the Commission allowed BHE to offer a Commercial Space Heating program under similar conditions to those imposed for the residential space-heating program. *Bangor Hydro-Electric Company, Proposed Schedule Revisions for Commercial Space Heating Price (94-125 AMP),* Docket No. 95-707.

In June of 1998, BHE requested that these programs be allowed to continue beyond September 30, 1998, through February 2000. The Commission granted this request, subject to continuation of the conditions imposed on these programs in Docket Nos. 95-701, 95-702 and 95-707. The Commission further noted that the ratemaking treatment for, and the continuation of, these programs beyond February 29, 2000, would be examined in the instant proceeding.

In response to the revenue adjustment mechanism ordered by the Commission in Docket Nos. 95-701, 95-702 and 95-707, the Company proposed a rate-year revenue space-heat adjustment of approximately $390,000 in its direct filing in the instant proceeding. The Bench Analysis asserted that the Company's estimate was too low and suggested that the adjustment should actually be as high as $1.5 million. The Bench Analysis identified concerns with: the Company's support for the assumption that, without the discount programs, space-heat sales would have continued to decline beyond September 30, 1998 at a rate of 4% per year; the Company's assumption that, absent the discount, space-heat load would have been served at 9¢/kWh rather than the retail rate; the Company's exclusion of the commercial space-heat program from the revenue adjustment; the Company's assumption that, absent the discount, the non-space-heating sales to space-heating customers would have remained at the 1993 level and inconsistencies in the data supplied by the Company.

In its surrebuttal filing, the Company revised its proposed rate year revenue space-heat adjustment to approximately $579,000. Based on our review of the Company's direct filing, the concerns raised in the Bench Analysis and the Company's response to these concerns, we adopt a rate year space-heat revenue adjustment of approximately $1.1 million.[7] We will discuss our findings on each of these issues, individually.

In addition to determining the appropriate level of revenue adjustment that should be made to the rate year revenues, we must also consider whether BHE should be allowed to continue offering these programs, and if so, what ratepayer protections should be instituted for the future. For the reasons described later, we do not prohibit BHE from offering these space-heat programs in the future.

(ii) Rate of Decline

a. Positions of the Parties

In its direct filing, the Company used the assumption prescribed by the Commission Order in Docket Nos. 95-701, 95-702 and 95-707 that, absent the discount, space-heat sales would have declined at a rate of 4% per year for each year from 1993 through the rate year. The Bench Analysis suggested that the 4% per year assumption was appropriate for the initial period of the program (through September 30, 1998), but should not necessarily be applied after that time. The Bench Analysis suggested that if the Company had data that supported using the 4% assumption after September 30, 1998, it should file such information, but that absent adequate support, no further decline in space-heat sales should be assumed after September 30, 1998.

In its surrebuttal filing, the Company provided regression analyses pertaining to the rate of decline of space-heat sales. Based on these analyses, the Company modified not only its assumption regarding the rate of decline for the period between September 30, 1998 and the end of the rate year, but also the period prior to September 30, 1998. In its surrebuttal filing, rather than using the 4% prescribed by the Commission's Orders in Docket Nos. 95-701, 95-702, and 95-707 the Company assumed that absent the space-heat programs, roughly 1/3 of the

[7] This number is based on estimated T&D retail rates. We are actually adopting the method used to determine this value, not the value itself. When the actual T&D retail rates are determined, they will be used in the space-heat revenue adjustment mechanism, and the resulting actual revenue adjustment may be different from the current estimate of $1.1 million.

1993 level of space-heat sales would have eroded at a rate of between 8% and 10% per year[8] and that the commercial space-heat load would have eroded at 12% per year.

b. Analysis and Decision

We reject the Company's erosion rates, and instead retain the erosion rate of 4%, for three major reasons. First, we agree with the Bench Analysis that it is not appropriate to revisit the erosion rate for the period 1993 through September 30, 1998 as this period was already considered, and the ratemaking treatment ordered for it, by the Commission in Docket Nos. 95-701, 702 and 707. Generally, we do not support re-litigating issues already reviewed and decided by the Commission.

That is not to say that, if we were provided compelling and reliable evidence that indicated an erosion rate of 4% was inappropriate for the period 1994 through 2000, we would not consider it. However, trying to determine what would have happened "absent the discount" is essentially an attempt to define a reality that never existed. This task is, at best, educated conjecture; we can never know with any certainty what would have actually occurred. Unfortunately, it is a necessary exercise if we are to protect ratepayers from the effect of a particular action. In approving these programs, the Commission determined that ratepayers would be protected by assuming that, absent the discount, space-heat sales would have declined at a rate of 4% per year, at least though September 30, 1998. As a general matter, without compelling and reliable evidence to the contrary, this decision should not be overturned. As described later, such evidence is not available in this proceeding.

Secondly, given that these regression analyses were provided at the surrebuttal stage of this proceeding, it is difficult to adequately assess their reliability. Moreover, parties were not afforded a procedural opportunity to respond to this complex and technical submission. The Bench Analysis requested information, to the extent it existed, to support continued use of the 4% rate of decline beyond the Commission-ordered termination date of the initial program. We view this request as merely an opportunity for the Company to provide additional support for a limited aspect of its adjustment estimate, not to comprehensively revisit its position. If the Company had wanted to apply a rate other than 4% as the rate of decline, it should have presented this in its direct filing, not its surrebuttal filing. These are complicated analyses that would require considerable effort and time to fully examine. Because they were presented at the surrebuttal stage, parties have not had the time, nor the procedural process to completely evaluate them. Without such a thorough review, it is impossible to determine their merit. Therefore, we conclude that these analyses do not provide an adequately critiqued alternative to the 4% rate of decline that was previously accepted and approved by the Commission.

[8] The Company did use the Commission's prescribed 4% erosion rate for the remaining 2/3 of the residential space-heat load.

Finally, based on our limited review of the regression analyses, the Company appears to rely on the rate of decline in years 1992 and 1993 of its regression analysis as support for the rate of decline for the entire period 1993 through 2000 for the residential class. The Company suggests that the large decline in years 1992 and 1993 was in response to rate increases between 1990 and 1992. Therefore, the Company applied a rate of decline between 8% and 10% for years 1994 – 2000.

We agree with the Bench Analysis that the rate of decline would likely be steeper in the initial years and flatter in later years (theoretically eventually flattening to a zero rate of change, all else equal) as the customers most inclined to limit their space-heating load will do so early and customers left are those who have no viable alternative or who favor space heat for convenience or other reasons. This is, in fact, supported by the Company's statement that, "[w]e believe that the threshold price acceptance by many, if not most of our space-heating customers for electric heat was exceeded during this time [between 1989 and 1992]." If this is true -- that the threshold price acceptance of most space-heating customers was exceeded between 1989 and 1992 -- it implies that these customers would then have eliminated electric space-heat usage to the extent they could, presumably as soon as possible. This again suggests that the rate of decline observed between 1992 and 1993 would have reflected the customers most inclined to leave and that such a rate of decline would not likely have been maintained. Thus, even if the Company's regression analysis was found to be accurate, it does not support applying the 1992 and 1993 rate of decline to all years from 1994 through 2000.

Therefore, for the reasons discussed above, we will apply a rate of decline of 4% from 1994 though September 30, 1998. We do not accept the Bench Analysis recommendation to assume a 0% rate of decline for the period from September 30, 1998 through the rate year. The Order that authorized continuation of the program through February 29, 1999, stated that such approval was "subject to conditions designed to protect ratepayers contained in the Orders approving the programs in Docket Nos. 95-701, 95-702 and 95-707." *Docket No. 98-465*, Order at 1 (Sept. 16, 1998). We read that to include the 4% assumption. We will, therefore, apply the decline rate of 4% per year for the full period 1994 through the rate year. Ratemaking for periods beyond that time is discussed later.

As shown in Attachment 2, using the 4% rate of decline through February 29, 2000 produces a space-heat adjustment approximately $248,000 higher than the Company's adjustment.

(iii) Retail Rate Space-heat Customers Would Have Paid, Absent the Discount

a. Position of the Parties

In its space-heating adjustment, the Company assumed that, absent the 5¢ discount rate authorized in Docket Nos. 95-701 and 95-702, space-heat load would have been served at the 9¢ discount rate approved in Docket No. 93-205 rather than the regular residential retail rate of 11.4¢. The Company claimed this was intended by the Commission's description of the mechanism to hold ratepayers harmless from the effect of the space-heating discount. The Bench Analysis disagreed with this and asserted that the Commission's description intended that the regular retail rate be used.

b. Analysis and Decision

We agree with the Bench Analysis that the adjustment mechanism was never intended to use a rate other than the core, residential retail rate to estimate the revenue that would have been received absent the program.

In the Order approving the 9¢ space-heat rate in Docket No. 93-205, this Commission specifically required that "BHE bear the risk of loss and that losses ... [not be] 'flowed through' to ratepayers." Order at 8. To use the 9¢ rate in place of the regular retail rate mechanism would, in fact, pass the revenue loss associated with the difference between the regular retail rate and the 9¢ rate directly on to ratepayers, contrary to the Docket No. 93-205 Order. The language in the Order that approved the 5¢ rate specifically required that the mechanism use the "otherwise available residential rate." Docket Nos. 95-701 and 95-702, Order at 5. In addition to the fact that the plain reading of this language implies the core residential retail rate, the 9¢ rate was a temporary rate from its inception, scheduled to expire on October 31, 1995 by the term of the Commission Order that approved it. Order in Docket No. 93-205. Therefore, it could not now be the "otherwise available residential rate."

As shown in Attachment 2, using the regular residential retail rate rather than the 9¢ rate in the adjustment mechanism, increases the residential space-heat adjustment by approximately $275,000 over the Company's estimate.

(iv) Exclusion of the Commercial Space-heat Program from the Adjustment

The Bench Analysis asserted that the Company failed to include the commercial space-heat program in its space-heat revenue adjustment provided in its direct filing. In its surrebuttal filing, the Company acknowledged this and included the commercial class in its space-heat revenue adjustment. We have reviewed the Company's commercial space-heat adjustment estimate and adopt it, with the exception of the 12% rate of decline which we will replace with a 4% rate of decline, for the reasons described earlier.

(v) Non-Heat Sales to Space-heat Customers and Data Inconsistencies

a. Position of the Parties

In its direct filing, the Company assumed that non-heat sales to space-heat customers would remain at their 1993 level through the rate year. The Bench Analysis suggested that this was inappropriate because a discount for space heat should not affect non-space-heat load. The Bench Analysis also identified data inconsistencies with respect to the Company's apportionment of the total sales made to space-heat customers between space-heat related usage and non-space-heat related usage.

In its surrebuttal filing, the Company agreed with the Bench Analysis that modification should be made with respect to both of these areas. The Company addressed the data inconsistencies by using the results of its regression analyses to apportion sales between weather-sensitive (i.e. heat) and non-weather-sensitive (i.e. non-heat) sales. The Company addressed the second area of concern, that the non-space-heat sales remained at their 1993 level, by applying the results of the space-heat/non-space-heat apportionment, to the total rate-year sales in its surrebuttal filing.

c. Analysis and Decision

We have reviewed the Company's response to these areas and find that they adequately address the concerns raised by the Bench Analysis. While we are uncomfortable relying on the regression analyses for purposes of the larger question of what would have happened absent the discount, we will rely on them for purposes of apportioning usage between heat and non-heat usage. We will do this for several reasons. First, unlike for the rate of decline, there is no Commission-ordered value to rely on so an estimate must be made in this proceeding. Second, BHE already had estimates produced from other methods in the record. The regression analyses appear to be more thorough than the other methods used to apportion the usage and the results appear to be relatively consistent with the previous results.[9] Such

[9] Prior to the regression analyses, the Company estimated that space-heat usage would have been approximately 41% of the total 1993 usage of residential space-heat customers and between 37% and 41% of their total rate year usage. Using the regression analyses, the Company estimates that space-heat usage would have been approximately 35% of the total 1993 usage of residential space-heat customers and approximately 39% of their total rate year usage. For commercial customers, prior to the regression analyses, the Company estimated that space-heat usage would be between 42% and 48% of the total rate year usage of commercial space-heat customers. Using the regression analyses, the Company estimates that approximately 30% of these customers' usage will be space-heat related.

consistency gives us some comfort. Finally, it should be a simpler exercise to evaluate the sensitivity of load to weather than to develop a regression that would reliably estimate the sales that would have occurred absent the discount. Therefore, while the Company's use of the regression to estimate space-heat sales absent the discount is too complex to review in the time available, use of the regression for the limited purpose of determining the actual ratio of heat sales to non-heat sales appears, based on a limited review, to be reasonable.

(vii) Future of Discount Rate Space-heat Programs

BHE has suggested that if "the Commission's revenue delta calculation falls within the Company's level of expectations," it will continue the program but that if it does not, "the Company intends to reconsider continuation of the program." In this Order, we have instituted conditions we find necessary to insulate ratepayers from negative impacts associated with these programs. As before, it will be up to BHE to determine whether it wishes to continue offering the programs under such conditions.

If BHE terminates this program, it must determine whether it is required under the provisions of our Order in Docket Nos. 95-701 and 95-702 to offer no-interest loans to those residential customers that installed new electric space heat as a result of this program. Under the conditions of that Order, BHE is required to offer such no-interest loans if the ratio of the 12-month average electric heat price (per kWh) divided by the 12-month average #2 heating oil price (per gallon) exceeds the equivalent ratio for the first year of the program by more than 40%. We do not expect this requirement to be a significant burden to BHE, even if it is required to offer such loans, as the Company estimates that only 69 customers have installed new electric resistance space heat since the program's inception.[10]

If BHE terminates this program, we require it to file an analysis with the Commission within 30 days of such termination, that demonstrates whether or not it is required by this condition to offer such loans. In performing this analysis, we require the Company to include in the price of electricity the price for standard offer generation.

If BHE continues to offer the discount space heat programs, we believe it is important, and have consistently expressed a desire, to shield ratepayers from the risks associated with these programs. Such protections are particularly important given the potentially significant revenue losses associated with these programs. The key to such ratepayer protection, of course, lies in the level of revenue imputed to the Company which, in turn, rests on the assumption of the rate at

[10] The number of new residential space-heat installations is taken from information filed by the Company in Docket No. 98-465. We took administrative notice of that information in the Examiner's Report issued on October 25, 1999. The Company has not disputed the accuracy of this number.

which sales would have declined absent the program. As discussed earlier, there is not adequate evidence in this proceeding to warrant a departure from the Commission's previously adopted assumption that absent the discount, space heat sales would have declined at a rate of 4% per year. We have therefore adopted a 4% rate of decline for purposes of setting rates in this proceeding. However, assuming the program continues, BHE may request that we open an investigation to consider what rate of decline should be used for future ratemaking. The results of such an investigation would be incorporated in the Company's next revenue requirement proceeding.

b. Discount Contracts

(i) Position of the Parties

The Bench Analysis proposed that the ratemaking treatment for the Company's discount contracts be based on three categories: 1) contracts entered into prior to the rate plan that did not receive Commission approval; 2) contracts entered into under the Company's rate plan or contracts that did receive Commission approval; and 3) new contracts. The Bench Analysis proposed that we treat the first category of contracts consistent with the Order in *97-116* and allocate to shareholders 15% of the difference between the revenues that would be received at the core T&D rates and the revenues that would be received at the contract T&D rates. The Bench Analysis proposed that for the second category of contracts, we use actual contract T&D revenues for ratemaking and for the third category, that we determine the appropriate ratemaking at the time we review the contract.

In its surrebuttal filing and its Brief, the Company argued that the 15% allocation to shareholders should not be adopted as suggested by the Bench Analysis. The Company asserted that the 15% sharing determined by the Commission to be appropriate in *97-116* should only apply to the period prior to March 1, 2000 and that applying the 15% to the rate year revenues results in an unfair penalty to BHE that was not applied to other utilities. The Company also argued that the approach proposed by the Bench Analysis creates an artificial distinction between ARP and AMP contracts; that applying the 85/15 split does not allow shareholders to break even, would constitute a post facto penalty, denies BHE the ability to re-base its rates following the AMP and creates improper incentives.

(ii) Analysis and Decision

We adopt the Company's recommendation that no further imputation associated with the revenue delta should be applied. We believe that the 15% imputation included in the prior rate case (97-116) produced an appropriate risk-shifting from BHE's discount offerings extended prior to its current ARP and that no further imputation is necessary or warranted. Therefore, for purposes of this proceeding, ratemaking for existing discount contracts will be done using their estimated T&D revenues.

D. Cost of Capital

1. Overview

The Company seeks the opportunity to earn an overall after-tax weighted average cost of capital (WACC) of 9.67% on its non-Ultrapower rate base. Company witness Mathieu Poulin recommends that BHE's capital structure include a 40.4% common equity ratio, and Company witness Dr. Robert Strong recommends a return on common equity (ROE) of 11.92%, a figure which includes a 32 basis point upward adjustment for equity flotation costs.

OPA witness Richard Baudino recommends an allowed ROE of 9.80% resulting in an overall after-tax WACC of 8.75% on BHE's non-Ultrapower rate base. This is based on the capital structure developed by OPA witness, Lane Kollen, which includes a 40.5% common equity component. Mr. Kollen also recommends that BHE's short-term debt component be eliminated from its proposed capital structure at this time. The OPA also recommends that the Commission reject a flotation cost adjustment for BHE. If any such adjustment is allowed, however, it should be 20 basis points as recommended in the Bench Analysis rather than 32 basis points proposed by the Company.

In its Bench Analysis, the Advisory Staff recommended that the appropriate ROE for BHE was 10.75% with a resulting after-tax WACC of 9.18% for the non-Ultrapower ratebase. All parties accepted that the Ultrapower rate base will continue to earn at the embedded debt cost rate of 7.49% consistent with the Commission's prior orders in Docket Nos. 97-116, 95-105 and 95-127. The Bench Analysis accepted the Company's originally proposed capital structure including a common equity ratio of 40.07% as well as its embedded cost rates on preferred equity and debt. The Bench's recommendation of a 10.75% return on common equity included a 20 basis point allowance for flotation costs.

For the reasons described herein, we find that the appropriate after-tax WACC for BHE's non-Ultrapower rate base is 9.28% with a corresponding pre-tax WACC of 12.37%. This is based on a cost of common equity of 11.00%, a figure which includes a 20-basis-point allowance for flotation costs, a 40.1% common equity ratio, and a short-term debt component consistent with that proposed by the Company.

2. Background on Cost of Capital

In determining a Company's overall revenue requirement, it is necessary to set a rate of return (ROR) that is applied to the Company's rate base. While the allowed rate of return is generally referred to as the cost of capital, there is a distinction between the two concepts. The WACC is simply the sum of the cost components of the capital structure after each of them are weighted by their respective proportions in the utility's total capitalization. At times, the allowed ROR can differ from the indicated WACC if subjective adjustments are made to actual cost elements or if a hypothetical capital structure is imputed for a company.

Judgment must be applied in arriving at the cost for each of the components of the capital structure. This is especially true with regard to developing a forward-looking estimate of the cost of common equity. Our analysis of the cost of capital, specifically the cost of common equity, sometimes implies a degree of precision that is not really present. Nevertheless, to calculate a revenue requirement, we must specify point estimates for the cost rate of each capital component to arrive at the overall cost of capital for the utility.

The allowed rate of return which is ultimately applied to rate base may contain certain subjective adjustments to the cost of capital that reflect management efficiency or other considerations related to the balancing of ratepayer and utility interests. The overall rate of return must strike a balance between the interests of ratepayers, who are entitled to the lowest reasonable cost of service, and the utility, which is entitled to a rate of return that allows it to attract capital at a reasonable cost.

This relationship between the cost of capital and the utility's fair rate of return has been established by several familiar United States Supreme Court decisions. *Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia*, 282 U.S. 679 (1923); *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944); and *Permian Basin Area Rate Case*, 390 U.S. 747 (1968). The *Hope* and *Bluefield* cases establish the general principle that returns to common shareholders of utilities should be commensurate with returns on alternative investments having corresponding risks. In addition, returns should be sufficient to ensure confidence in the financial integrity of the enterprise in order to maintain its credit quality and ability to attract capital. In *Permian Basin*, the Court tempered the strict reliance on the returns paid to investors with the acknowledgement that commissions must consider the "broad public interest" when making decisions on the utility's rate of return. *Id.* at 791.

The Maine Law Court has also required that the Commission consider the interests of ratepayers when setting the rate of return. For example, in *New England Telephone and Telegraph Company v. Public Utilities Commission*, 390 A.2d 8, 30-31 (Me. 1978), the Law Court held that ratepayers' interests must be given substantial weight in the final determination of a utility's allowed rate of return. In prior cases, we also have made cost-of-equity adjustments to account for utility inefficiency. We have generally used such adjustments when the effect of the inefficient behavior results from inaction rather than action. *See* e.g., *Bangor Hydro-Electric Company, Proposed Increase in Rates,* Docket No. 86-242, Order at 17-50 (Me. P.U.C., Dec. 22, 1987) (25 basis point reduction on equity because of management inefficiency in the credit and collection and conservation and demand-side management areas). In this case, we have been presented with no evidence that would lead us to adjust the cost of capital for any of these concerns. Thus, we can and will use the terms "cost of capital" and "rate of return" interchangeably.

3. Cost of Equity

a. Positions Before the Commission

Dr. Strong made a final recommendation of an 11.92% cost of equity for BHE, based primarily on a DCF analysis on a peer group of electric utilities. Dr. Strong presented an updated analysis in his surrebuttal testimony that resulted in a downward adjustment of 75 basis points from what was originally a recommendation of 12.67%. Both the original and final recommendations made by Dr. Strong included a flotation cost adjustment of 32 basis points. Dr. Strong also performed a CAPM analysis on his peer companies principally as a check. In his surrebuttal testimony, Dr. Strong's CAPM analysis yielded an estimated ROE of 11.32% before flotation costs.

On behalf of the OPA, Mr. Baudino recommended a 9.80% ROE for BHE based upon a discounted cash flow (DCF) analysis on three separate utility groups. He examined a peer group of electric utilities, a peer group of natural gas local distribution companies (LDC's) and a peer group of water utilities and established a DCF cost of equity range of 8.86% (water utilities) to 10.65% (LDC's), not including flotation costs. The midpoint of these estimates is approximately 9.76%.

To confirm his DCF findings, Mr. Baudino originally used a Capital Asset Pricing Model (CAPM) model on his three utility peer groups. In surrebuttal, Mr. Baudino relied exclusively on his electric utility peer group and concluded that the appropriate CAPM range was between 7.05% and 9.36%, with an indicated midpoint of 8.21%. With regard to flotation costs, Mr. Baudino stated that such adjustments were unnecessary as they were already taken into account by investors. He did, however, recommend that if the Commission were to adopt a flotation cost adjustment, that it should adopt the Bench's proposal of 20 basis points rather than the 32 basis points recommended by the Company. If the Commission accepted Mr. Baudino's recommendation of 9.80% plus a flotation costs, it would result in an all-in ROE of 10.00% for BHE.

Staff's Bench Analysis relied primarily on the quarterly version of the DCF Model applied to four utility peer groups to arrive at a cost of equity of 10.75% for BHE. Staff also employed the annual version of the DCF model and a CAPM analysis as check methodologies. The Bench's four peer groups included two separate (but in some cases overlapping) electric utility peer groups, a natural gas LDC peer group, and a water utility peer group. The Bench largely discounted the water utilities as a "true" peer group for BHE and considered the DCF results on the group to be indicative of a "floor level" for the rest of its analysis. The quarterly DCF model produced a ROE range of 10.45% to 11.00% (with an approximate midpoint of 10.75%) inclusive of 20 basis points for flotation costs. The annual DCF results suggested a range that was lower by roughly 5-10 basis points at 10.40% to 10.90% (with an indicated midpoint of 10.65%), also inclusive of 20 basis points for flotation costs. The Advisory Staff's flotation cost-adjusted CAPM yielded ROE estimates from 9.70% to

11.15% (with an indicated midpoint of 10.45%). Advisory Staff's recommendation of a 20 basis point flotation cost allowance was based on a survey of common stock issues made by electric utilities between 1994 and 1998.

4. Comparable Sample Groups

a. Positions Before the Commission

BHE witness Dr. Strong used the familiar cluster analysis technique to identify a peer group of electric utilities for use in his DCF and CAPM analyses. Dr. Strong used *Value Line' s* "Eastern" electric utilities (38 companies not including BHE) as the starting point for his selection process. After adjusting out companies for which there were no 1997 data points available, Dr. Strong was left with 28 companies. He then calculated or collected 5 historical risk variables (or ratios) for each of these companies. The 5 variables included 4-year averages[11] of each of the following ratios: (1) Cash flow per Share to Price per Share; (2) Common Equity Ratio; (3) Earned Return on Equity; (4) Price to Earnings Ratio, and; (5) Dividend Yield.

OPA witness Baudino did not comment on Dr. Strong's peer group selection process. The Bench however did highlight several areas of concern regarding Dr. Strong's selection technique. First, the Bench noted that Dr. Strong's decision to use only the "Eastern" *Value Line* electric utility universe as a starting point for his cluster analysis artificially eliminated a substantial portion of the industry based on geography alone. Bench Analysis at 15. Second, the Bench expressed concern that Dr. Strong failed to remove companies that were either not paying dividends or that had announced mergers during the period in which Dr. Strong would be measuring dividend yields or dividend growth rates for a subsequent DCF analysis. A final, but minor, point noted by the Bench was that two of Dr. Strong's risk measurement variables, the Cash Flow/Share to Price/Share Ratio and the Price to Earnings Ratio, might be measuring the same risk factor thereby double-counting that factor in his final cluster analysis summation.

Mr. Baudino constructed three different peer groups; one comprised of electric utilities, one of natural gas LDC's and one of water utilities, which he used throughout his analysis. Mr. Baudino used the *Value Line* (Basic Edition) universe of companies as the starting point for his peer group selection. In all three peer groups, he eliminated companies if they: (1) were not paying dividends; (2) had announced mergers during his measurement period; (3) had "significant" diversified operations; (4) had recently cut dividends, and; (5) were experiencing "non-constant" growth. Mr. Baudino updated his electric utility peer group between his Direct and surrebuttal filings and ended up using bond ratings (either BBB for Standard & Poor's or Baa for Moody's) as his final screening criterion in addition to the common criteria outlined above. For his natural gas LDC peer group, Mr. Baudino used the common criteria as well as the *Value Line's* "Safety Ranking" as the final screening filter. Given

[11] Dr. Strong response to 5-Examiners-68 to Direct Testimony.

the small number of water utilities available for consideration, Mr. Baudino used any of *Value Line's* Basic Edition water utilities that fit the common criteria as specified above.

The Company did not offer any specific criticisms of Mr. Baudino's peer group selection process. The Bench noted that three of Mr. Baudino's original natural gas LDC peer companies (NUI, Inc., Indiana Energy, and Energen Corp.) appeared to have either a high level of diversified operations or a lower degree of risk than what he originally specified. On surrebuttal, Mr. Baudino agreed and subsequently eliminated these companies from his peer group. He also eliminated Connecticut Energy from his LDC peer group due to its announced merger with Energy East Corporation in late April.

The Bench Analysis constructed two electric utility peer groups, a natural gas LDC peer group, and a water utility peer group for use throughout its analysis. The Bench's specified that all companies: (1) must be paying a common dividend; (2) must have a published consensus long-term growth rate from I/B/E/S; and (3) must not have announced mergers prior to the point when Staff measured each company's share price for its DCF analyses.

The first peer group was a so-called "Cluster Analysis" electric peer group. The cluster analysis methodology minimizes the geometric "distance" between a target company and others based on a number of risk measures. Staff calculated six ratios, three of which were meant to approximate business risk and three meant to determine financial risk, and compared BHE against the *Value Line* (Basic Edition) universe over the 3-year period 1996, 1997 and 1998. The ratios used were the: (1) Cash Flow per Share to Capital Expenditures per Share; (2) Electric Revenues as a Percent of Total Revenues; (3) Residential Electric Revenues as a Percent of Electric Revenues; (4) Pre-tax Interest Coverage; (5) Common Equity as a Percent of Total Capital, and; (6) Operating Income as a Percent of Total Revenues. From the starting point of the 79 electric utility universe followed by *Value Line*, Staff selected the 18 most comparable companies to BHE based on natural breaks in the geometric distance calculations. After eliminating companies which were not paying a dividend, or for which there was no I/B/E/S long-term earnings growth estimate available, or which had announced mergers, the Bench's Cluster Analysis peer group was narrowed to 12 companies. The companies comprising the Cluster Analysis peer group have average bond ratings in the High Triple-B to Low Single-A range (BBB+ to A- for S&P, Baa1 to A3 for Moody's).

The second electric peer group was made up of 12 companies selected primarily on the basis of bond ratings. Staff examined both S&P and Moody's bond ratings and found 29 companies that were rated "Triple-B" or lower (BBB+ for S&P, Baa1 for Moody's) by at least one of the two agencies. Seven companies were eliminated due to merger announcements,[12] and six more were eliminated because they were either not paying common dividends or because there was no I/B/E/S growth rate available.[13] Since Staff's objective was to identify the peer group with the lowest industry-wide bond ratings, four additional companies were eliminated that were more "highly" rated than others in the group. These companies were rated by both agencies and had at least one rating above BBB+(for S&P) / Baa1(for Moody's) while the other rating was at either BBB+ or Baa1.[14] The companies in this electric utility peer group have an average bond rating in the Mid Triple-B range (BBB for S&P, Baa2 for Moody's).

Staff selected its 8-company natural gas LDC peer group in a similar manner as Mr. Baudino. For all intents and purposes, Staff's' LDC peer group is comprised of companies where the majority of revenues are derived from natural gas distribution (South Jersey Industries at 66% of total is the lowest). The companies in this peer group appear to have, on average, a bond rating in the Low to Mid Single-A range (A- to A for S&P, A3 to A2 for Moody's).

Staff's final peer group was comprised of water utilities. In addition to the Basic Edition *Value Line* companies, the *Value Line's* Expanded Edition companies for which I/B/E/S earnings estimates were available were added to arrive at an 8-company sample group. The companies in this group have an average bond rating in the Mid to High Single-A range (A to A+ for S&P, A2 to A1 for Moody's).

Neither the Company nor the Public Advocate offered specific comment on Staff's selection criteria for peer companies.

b. Analysis and Conclusion

We believe that peer group analysis performs an essential role in setting the cost of equity by eliminating or reducing the likelihood of reaching an anomalous conclusion, which could occur if analysis were limited to a single company. We have in this case, due to the restructuring of the utility industry, chosen to consider other utility industries that remain largely regulated in order to determine where on the risk spectrum a regulated T&D-utility falls. As such, we agree in principle that integrated

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[12]TNP Enterprises, Utilicorp United, BEC Energy (Boston Edison), Eastern Utilities, Energy East, Inc. (NYSEG), Commonwealth Energy (Ma.), Nevada Power were removed to mergers.

[13]CMP Group, Green Mountain Power were removed for lack of a growth rate, while Niagara Mohawk, Northeast Utilities, UniSource Energy & El Paso Electric were not paying common dividends.

[14] Reliant Energy at BBB+/A3, Pinnacle West, Montana Power, and Pugent Sound Energy at A-/Baa1 were removed from the sample.

electric utilities, natural gas LDCs and to a limited degree, water utilities should be considered in our analysis.

In general, we believe that an appropriate selection process should initially consider a large number of potential candidates. Furthermore, the final selection should be based on systematic and objective criteria that properly identify companies that are most comparable to the subject company in terms of risk (and therefore in terms of required return). We specifically noted this criterion in Docket No. 97-116. Order at 44. By using only *Value Line's* population of "Eastern" electric utilities rather than its entire universe of electric utilities as a starting point, and thereby eliminating more than half of the companies in the electric utility industry, Dr. Strong disregarded this concern.

We made two other observations in Docket No. 97-116 that we believe to be relevant in this case. First, we considered it inappropriate to use companies that were not paying dividends in a DCF analysis. *Id.* at 45. Second, we expressed the opinion that we preferred forward-looking dividend growth rates to historical growth rates in a DCF analysis. Finally, in Docket No. 97-580 (Phase I) we made a third observation that is significant in this case. We stated that the inclusion of companies that had announced mergers in a peer group would cast "serious doubts upon any analyses based on that peer group." Order at 46. We believe that companies falling into any of these categories noted above should not be included in a peer group where a DCF analysis will be used. When we adjust for these faults, the combined impact on Dr. Strong's July 28 Surrebuttal peer group appears to be devastating. We note that Northeast Utilities and Niagara Mohawk were not paying dividends, that CMP Group and Green Mountain Power did not have published forward-looking I/B/E/S growth rates available, and finally, that Boston Edison, Dominion Resources, CMP Group and Eastern Utilities had announced mergers. This reduces a 10-company peer group to a 3-company peer group made up of GPU, Inc., DQE, Inc., and Constellation Energy (formerly Baltimore Gas & Electric). At hearings Dr. Strong acknowledged that he "would not use a 3-company peer group" for analysis. Given our opinion that the use of seven of Dr. Strong's companies is inappropriate and our concerns about the truncated starting universe, we will not rely on Dr. Strong's peer group in our final analysis.

We are left to consider the peer groups provided by OPA witness Baudino and the Bench Analysis. For the most part these peer groups are fairly consistent. Mr. Baudino essentially adopted the Bench's "Bond Rating" electric and natural gas LDC peer groups, making only minor modifications by removing NiSource Energy, Inc. and CTG Resources, Inc. respectively due to their merger announcements between the dates of the Bench Analysis and his surrebuttal filing. Mr. Baudino's water utility peer group differed from the Bench's peer group, due to his exclusion of three companies from *Value Line's* Expanded Edition, his inclusion of California Water Service, which does not have an I/B/E/S growth rate, and his unexplained exclusion of Philadelphia Suburban Corporation. We believe Philadelphia Suburban may have been excluded in Mr. Baudino's direct filing due to its merger with Consumer's Water

Company. This merger has, however, been closed for some time and we see no reason why it should now be excluded. To the limited extent that we will consider a water utility peer group in this case, we will rely on the Bench's due to its larger sample size. Due to their substantial similarity, we will consider the "Bond Rating" electric and natural gas LDC peer groups presented by the OPA and the Bench in our final analysis.

As we have done in the past, we will also rely on the Bench's "Cluster Analysis" peer group of electric utilities in our analysis. The cluster analysis methodology provides an unbiased basis for identifying companies of comparable risk to BHE, and thus its cost of equity. Company witness Strong, agrees, at least tacitly, having presented his own cluster analysis for the record, while OPA witness Baudino did not offer any objection to using this method. We recognize that the use of historical financial and operating ratios for a 3-year period (1996-1998) is less than an ideal method for identifying comparable companies, especially in an environment where restructuring is occurring at individual state levels on differing timetables. However, considering that there is no such thing as a "consensus forecast" of financial statements available on a company by company basis, and that such forecasts would be inherently uncertain anyway, we believe that recent historical data is really the best available data for use in a cluster analysis. It is our view that a 3-year period is a sufficiently recent period and that the risk measures used in the Bench Analysis are appropriate for our purposes here.

Ultimately, we believe that our reliance on multiple peer groups is appropriate because to the extent that there may be minor weaknesses in one peer group, they can be offset by strengths of another group. We are satisfied that each peer group described above provides us some useful information (e.g. water utilities help determine a floor) that will allow us to determine an appropriate cost of equity for BHE. These peer groups include companies that are, at the very least, primarily utilities, and they encompass what we consider to be the relevant range of risk profiles as determined by bond ratings. At one end of the spectrum is the "Bond Rating" electric utility peer group, which carries a Mid Triple-B risk level, and at the other end are the water utilities at the Mid/High Single-A risk range.

5. Discounted Cash Flow Analyses

a. Positions Before the Commission

As we described in the previous section we have decided not to consider Company witness Strong's peer group and as such we will not consider his DCF analysis. We do however offer a brief summary of his methodology here. Dr. Strong calculated the average dividend yield for his peer group based on the individual published (by *Value Line*) one-year average dividend yields for each company. He then multiplied the resulting average current yield by (1+g%) to determine a forward dividend yield. Dr. Strong used consensus I/B/E/S growth rates as his "g%" in this calculation. After summing the various yield and growth components and determining an ROE range, Dr. Strong made an upward adjustment to account for his perception that BHE was riskier than his peer group. He began by deeming only the top of his DCF range to be relevant and then used the historical standard deviation of returns as a risk variable to arrive at an ROE that was roughly 300 basis points, or 30%, higher than the top end of his calculated DCF range. Dr. Strong then added a 32 basis point flotation cost adjustment to reach his final recommendation. Regarding Dr. Strong's secondary adjustment, the Bench opined that if it had been more properly made from the middle of his indicated DCF range rather than from the top end, the resulting ROE estimate for BHE would have been somewhere between 10.72% and 11.10%. Dr. Strong did not dispute Staff's calculations.

OPA witness Baudino performed a traditional DCF analysis on each of his peer groups. For his current dividend, he used a historical 6-month average yield for each company and then considered both I/B/E/S and forward-looking "b times r" growth rates to arrive at ROE ranges for each peer group. The so-called "b times r" calculation of the growth rate is based on *Value Line* estimates of future earnings retention rates ("b" or earnings that are not paid out as dividends) and future earned returns on equity ("r"). Mr. Baudino converted his current dividend yields into forward yields by multiplying the current yield by the factor : ½ (1+g%). His rationale for using half the growth rate is because companies change their dividends at different times of the year. Therefore, he did not wish to increase the dividend of a company that could be within 3 to 6 months from raising its current dividend again. Mr. Baudino's position is that doing so would result in a sort of "double-counting" effect for the forward dividend yield. The Bench disagreed with using only half the growth rate to determine the forward yield, noting that the DCF model requires that the "next period" be used. Staff also disputed Mr. Baudino's use of a 6-month historical dividend yield as the starting point for determining the forward yield, stating a preference for the most recent 1-month yield.

To determine an ROE range for each peer group, Mr. Baudino added the average forward dividend yield for the group to the average I/B/E/S growth rate for the group to determine one end of his range. He then added the average forward yield for the group to the average "b times r" growth rate for the group to determine the other end of his range. For Mr. Baudino's electric utility peer group, this resulted in a cost of equity range of 9.62% to 10.23% with a midpoint of 9.92%. For his natural gas LDC peer group, the applicable range was 10.62% to 10.65% while the water utility range was 8.60% to 9.11% with a midpoint of 8.86%. Mr. Baudino's final recommendation of 9.80% is roughly consistent with the middle of the DCF range indicated by his water (8.86%) and natural gas LDC (10.65%) peer groups and did not include a flotation cost adjustment. In the Bench Analysis, Advisory Staff raised the question of Mr. Baudino's interpretation of his own results, and showed in Exhibit COC-24 that Mr. Baudino's figures could be shown to support wider ROE ranges.

The Bench used DCF analyses for each peer group to estimate the cost of equity of BHE and placed greater weight on the results produced by the quarterly version of the DCF model. Staff's quarterly DCF (including a 20 basis point flotation cost adjustment) range was 8.20% to 11.90% for the Cluster Analysis electric sample, 8.40% to 12.90% for the Bond Rating electric sample, 9.70% to 12.90% for the natural gas LDC sample, and 7.30% to 10.50% for the water utility sample. The annual DCF model produces estimates on the order of 10 to 15 basis points lower across the board. The Bench DCF recommendation was 10.75%, the midpoint of the range 10.50% (top of the water utility group's DCF range) to 11.00% (average of the midpoints of the bond-rating electric and the LDC range).

In its DCF analyses, Staff used the following inputs for each company: (a) 20-day average closing stock prices from April 29 to May 26, 1999; (b) May 1999's consensus 5-year I/B/E/S earnings growth rates ("g%") and; (c) the indicated current dividends raised by a factor of (1+g%) to arrive at a forward looking dividend yield. No party disputed the inputs to the Bench's quarterly or annual DCF models. However, Mr. Baudino did dispute Staff's interpretation of its own results, arguing that Staff gave too much weight to certain results that he considered to be outliers, thus causing an upward bias in Staff's final recommendation.

b. Analysis and Conclusion

We find that the DCF analyses provided by the Advisory Staff and the OPA provide a reasonable basis for determining BHE's cost of common equity but we will rely more heavily on the Bench's recommendation. Although their common peer groups are virtually identical, we continue to have concerns about certain methodologies used by Mr. Baudino which were highlighted in the Bench Analysis. In addition we have a further concern regarding some of his specific calculations, which we will explain below. We decline to rely on Dr. Strong's DCF analysis due to our discomfort with his peer group as well as with his secondary adjustment methodology. We believe that the conclusions on pages 15 to 17 of the Bench Analysis regarding the use of Dr. Strong's historical standard deviation adjustment are correct.

To address the more important issue of the opposing views regarding the final interpretation of their DCF results, we must first address three areas of disagreement between Mr. Baudino and the Bench. These involve which current yield to use as a starting point to determine a forward yield, whether to raise the current yield by one-half or by the full growth rate in that determination, and whether the quarterly or annual version of the DCF model is preferable.

We generally agree with the conclusions stated in the Bench Analysis. It is difficult theoretically to accept that a 6-month old dividend yield is truly indicative of investor's current expectations. Mr. Baudino acknowledges this on page 27 of his surrebuttal stating "[a] 20-day period may be somewhat closer to the theoretical requirement of the DCF model." As for how much of the growth rate to use in order to raise the current dividend yield to the corresponding forward yield, it seems intuitive that the appropriate dividend for the DCF model is the "next period" dividend even if the current dividend amount has just been increased. Assume for a moment that a firm raised its annualized dividend per share from $0.96 to $1.00 yesterday and it has an expected growth rate of 4%. Since the DCF requires the next period dividend, that requires $1.04 on an annualized basis (or $0.26 rather than $0.25 on a quarterly basis) not $1.02 as using half the growth rate would imply. The final area of disagreement involves the Bench's stated preference for the quarterly DCF model over the annual DCF model. Reiterating our view as stated in *97-580*:

> [a] fundamental premise of financial theory is that a dollar today is worth more than a dollar tomorrow. We believe that investors value a quarterly dividend more highly than an annual dividend, and to the extent an adjustment to accommodate this belief can be easily incorporated into the DCF model, we will consider it.

Order at 51. We note that the evidence presented here indicates that the difference between the quarterly and annual DCF models is rather small, on the order of 10 to 15 basis points. With this in mind we can move on to the interpretation differences between the Bench and Mr. Baudino.

We agree with Mr. Baudino that there are instances where certain outlying ROE estimates shown in the Bench Analysis should have been disregarded. On surrebuttal, Mr. Baudino singled out three companies, CMS Energy, Atmos Energy and United Water Resources from Staff's Bond Rating, natural gas LDC and water utility peer groups, respectively, as driving an overstated ROE recommendation. As we will explain further later, we are of the opinion that the risk profile of a T&D electric utility is between that of the water utility industry at the low end and that of the existing electric utility industry at the upper end. For that reason, we will not remove Atmos Energy from Staff's natural gas LDC peer group. However, we agree with Mr. Baudino's point that as a measure of central tendency, the midpoint is most susceptible to bias by a single outlier and, therefore, we will not weigh that company's DCF estimate as heavily here as the Bench did. We will simply note that our final recommendation of 11.00% for BHE is above both the median and average Bench Analysis ROE estimates of roughly 10.50% and 10.70% (allowing 20 basis points for flotation costs) for the LDC peer group.

With regards to United Water Resources, while we continue to believe that the water utility industry provides us with a floor ROE to use in our range, we share the OPA's concern that United Water Resources is an outlier for the water utility peer group. Our concern is based on the fact that the average, midpoint and median estimates are in the 8.50% to 8.70% range and that the next highest value for the group is roughly 9.70%. United Water Resources 10.30% certainly seems out of line with the rest of the group and is also markedly higher than the average and median electric and natural gas LDC estimates showed on Exhibit COC-1 of the Bench Analysis. We will, therefore, move to the next highest estimate in the group and use 9.70% as the bottom end of the reasonable range for BHE.

We also have concerns about the true comparability of CMS Energy's risk profile to that of a T&D utility and will, therefore, drop it from Mr. Baudino's and Staff's Bond Rating peer groups. CMS has an extremely high I/B/E/S growth rate that, which upon further investigation, appears to be primarily due to high-risk unregulated ventures. At hearings, BHE presented BHE Exhibit 10 which, among other things, includes the *Value Line* reports relied on by Mr. Baudino in his analysis. In its July 9, 1999 report on CMS, *Value Line* noted that roughly 20% of CMS's operating income is derived from the combination of independent power projects, oil/gas exploration and production and energy marketing. *Value Line* went on to state that the company's "star performer" is its independent power group. We interpret this statement to mean that it will be a primary driver of future earnings growth. In addition, BHE provided BHE Exhibit 23 at hearings, which included Staff's cluster analysis database showing that electric utility sales amounted to roughly half of CMS's total revenues over the 1996, 1997, 1998 time periods. We believe that CMS's very high I/B/E/S growth rate is a reflection of a higher risk profile due to its investments in high-risk (relative to electric or LDC utilities) independent power projects and oil/gas exploration and production ventures. Eliminating CMS from Staff's Bond Rating peer group leaves 11.49% as the upper end of the peer group range (using the quarterly DCF model) which is not far from the top end of Staff's Cluster Analysis peer group range of 11.68%. Therefore, we define the top end of our reasonable DCF range to be 11.70% (before flotation costs) based on the top end of Staff's Cluster Analysis peer group range.

We believe that from an ROE standpoint, each company in a DCF analysis should be evaluated in total. That is, each company's individual yield and growth components are interdependent and should not be separated. Investors evaluate companies on both yield and growth and when one of the two components is low the other may have to be higher to compensate. We believe that Mr. Baudino erred when he added average peer group growth rates to his average peer group yields to arrive at his final ranges. It is our opinion that he should have evaluated each company's total ROE to define his relevant ranges. In the table below, we calculate our interpretation of Mr. Baudino's reasonable peer group ranges using data from his surrebuttal filing. Specifically we use his 1-month current dividend yield, the I/B/E/S growth rate, and we exclude CMS Energy, Atmos Energy and United Water Resources from each peer group. We also excluded Aquarion due to its merger announcement and California Water Service from the water group as it currently lacks an I/B/E/S growth rate.

	1-Mo. Yield%	I/B/E/S Growth%	Forward Yield%	Indicated ROE
Electric				
TXU	5.38%	6.00%	5.70%	11.70%
PE	2.21%	5.70%	2.34%	8.04%
Midpoint				9.87%
Gas LDC				
PVY	4.47%	7.70%	4.81%	12.51%
CGC	5.31%	3.50%	5.50%	9.00%
Midpoint				10.75%
Water				
AWK	2.86%	6.50%	3.05%	9.55%
ETW	4.55%	3.00%	4.69%	7.69%
Midpoint				8.62%
ROE Range =	9.55%	11.70%	Midpoint =	10.63%

The above table indicates that the Mr. Baudino's adjusted range of 9.55% to 11.70% is very similar to the one we derived using the Bench's data. This is not surprising given that the peer groups are virtually identical and the methodology is the same. This does indicate to us that market conditions did not change significantly between the early June filing date of the Bench Analysis and the filing of Mr. Baudino's Surrebuttal in late July. We note that adding 20 basis points for flotation costs and 10 basis points for the quarterly DCF model would result in a midpoint range of 10.93%, which is very close to our final recommendation.

6. Capital Asset Pricing Model

a. Positions Before the Commission

Company witness Strong proposed a CAPM model that used the 1-year Treasury Bill, currently yielding 5.02%, as the risk-free rate and a beta of 0.75 for BHE. His equity market risk premium of 8.40% is based on the 1926 to 1997 historical average spread between large company stocks and U.S. T-Bills as calculated by Ibbotson Associates. Dr. Strong's beta estimate was apparently published in *Value Line for Windows* in July 1999. Dr. Strong did not consider the average beta of 0.63 indicated by his electric utility peer group. Mr. Baudino questioned Dr. Strong's use of the historic Ibbotson equity market risk premium. Staff expressed concerns about both Dr. Strong's 1-year T-Bill as the risk free rate and about his beta estimate, which the Bench contended is actually 0.60 per *Value Line's* (Expanded) hard copy edition.

Public Advocate witness Baudino used four versions of the CAPM model, primarily as a check methodology for his DCF results. He used two different estimates of the risk free rate and two different equity market risk premiums to develop a CAPM range of 7.05% to 9.36%, before flotation costs. For his beta estimate, Mr. Baudino used 0.60, the average for his electric utility peer group. Mr. Baudino calculated his risk free rates by taking the 6-month average yields of both the 5-year Treasury Note and the 30-year Treasury Bond, which were 5.16% and 5.59%, respectively. Mr. Baudino based his equity market risk premium on a DCF approximation of the cost of equity of the S&P 500 index and of the *Value Line* Composite Industrial Index. He obtained an expected equity market return of 8.32% for the S&P 500 index and 11.88% for the *Value Line* index. These values suggest an equity market risk premium range of 2.73% (equal to 8.32% - 5.59%) to 6.72% (equal to 11.88% - 5.16%). Staff and Dr. Strong both expressed concerns regarding Mr. Baudino's equity market risk premium, noting that based on historical relationships, his equity market risk premium was rather small.

The Bench Analysis includes a CAPM analysis as a check methodology. Its model employed a risk-free rate of 5.80%, based on the then current (June 1, 1999) 30-year T-Bond. The Bench, in a departure from its usual practice of calculating a forward-looking market risk premium, used the Ibbotson Associates data to calculate the equity market risk premium of 7.36% but, unlike Dr. Strong, used the premium between large company stocks and long-term U.S. T-Bonds. The beta estimates used were those of the individual companies included in its four peer groups and ranged from 0.45 to 0.70. Mr. Baudino contended that Staff erred in using the historical equity market risk premium rather than one that was forward-looking. Dr. Strong did not specifically comment on Staff's CAPM analysis.

b. Analysis and Conclusion

As we have found in past cases, specifically in *97-116* and *97-580*, we find that the CAPM results provide, at best, a useful check on the DCF analyses. We have noted in the past that the theoretical weaknesses of the CAPM, primarily the difficulty in identifying a true forward-looking beta, cause us to rely more heavily on the DCF analysis. The lack of a true forward-looking beta is a larger obstacle than usual here given the fact that a pure T&D-only utility industry does not exist at this time. The CAPM is familiar to us, and thus we need not discuss the basic structure of the model in this order.

We will not rely heavily on Dr. Strong's CAPM analyses for several reasons. First, we are not convinced that his beta estimate of 0.75 is reasonable for BHE. The September 10, 1999 *Value Line* Expanded Edition indicated that BHE's current beta estimate is 0.60. In addition, Dr. Strong's peer group average beta was only 0.63 and many of the companies in his peer group are fully integrated utilities. It is our belief that the future T&D-utility industry will be less risky than today's fully integrated electric utility industry and, therefore, integrated utility betas would accordingly represent an upper boundary for the beta of a T&D-only utility. Dr. Strong appears to share this view as he testified that BHE would be a lower risk company in the future than it is today. Yet, Dr. Strong did not adjust his recommended beta downward to account for that fact. One final point is that Dr. Strong also used a risk-free rate based on the recent 5.02% yield of a 1-year T-Bill instead of a 3-month T-Bill as he has done in the past. In data responses and at hearings, he acknowledged that he should have been consistent and that the recent yield on the 1-year T-Bill exceeded that of the 3-month T-Bill by 30-35 basis points.

With respect to Mr. Baudino's CAPM models, we agree with the Bench and Dr. Strong that equity market risk premium estimates of 2.72% and 3.16% based on his analysis of the S&P 500 index appear to be unreasonable given history and the current low interest rate economic environment. Even his larger premiums derived from the *Value Line* Index (of 6.29% and 6.72%) would appear small if one believes that the size of the equity market risk premium varies inversely with the level of interest rates. Mr. Baudino indeed acknowledged at hearings that academic studies indicate this to be the case. We have one other issue with Mr. Baudino's CAPM analysis. Regardless of which Treasury security is chosen as the risk free rate instrument, we would use the most recent yield rather than a 6-month average because this is most representative of "the market's" current view of the future.

Despite these concerns, we are hesitant to completely disregard his CAPM analysis at this time for several reasons. Our preference for forward-looking equity market risk premiums is well documented, most recently in *97-116.* Regardless of our perception of the size of Mr. Baudino's estimated premium, the fact remains that no other party provided us with a true alternative forward-looking estimate. Therefore, we believe it would be unwise to completely ignore this evidence. In addition, Mr. Baudino has also provided us with the most current beta estimates for the "Bond Rating" electric utility peer group as well as the most recent 30-year T-Bond yield, which is our preferred risk-free rate.

Regarding Staff's CAPM analysis, we agree with Mr. Baudino's criticism that a forward-looking equity market risk premium should have been used. The use of the 30-year T-Bond as a risk free rate and the beta estimates used in the Bench Analysis appear reasonable. Despite the weakness noted by Mr. Baudino, we also consider Staff's CAPM analysis below.

Because we are using the CAPM as a check methodology only, we can make certain assumptions about the inputs to the model. In this case, we believe that the equity market risk premium is somewhere between Mr. Baudino's 6.50% (average of Mr. Baudino's *Value Line* Index risk premiums of 6.3% and 6.7%) and Dr. Strong's 8.40%. We understand that Dr. Strong's 8.40% was based on short-term T-Bills rather than on long-term T-Bonds, but we are concerned about the inverse relationship between the size of the equity market risk premium and the level of interest rates given today's low interest rate environment. It is entirely possible that Staff's proposed 7.35% risk premium, which even though properly matched against long-term T-Bonds, may understate the current equity market risk premium. This is possible based on the premise that an "average" sized risk premium would theoretically correspond to an "average" level of interest rates. With current 30-year T-Bond rates in the 6.00% range, we view the present as a low rate period that perhaps could justify an above average sized risk premium. The table below computes what we consider to be the probable CAPM range for BHE. We have included the midpoint beta ranges for the four peer groups shown on COC-17 to the Bench Analysis (0.55-0.60), as well as 0.65, which is a rough approximation of the average beta of Dr. Strong's peer group. Mr.

Baudino's recommended beta of 0.60 is also obviously accounted for within this range. For the risk free rate, we use 6.05% based on the June 1999, 30-year T-Bond as shown in Exhibit RAB-10S to Mr. Baudino's surrebuttal filing, this being the most current estimate of the risk-free rate we have in the record.

		R_p	R_p	R_p
Beta (ß)	**R_f**	**6.50%**	**7.35%**	**8.40**
0.55	6.05%	9.63%	10.09%	10.67%
0.60	6.05%	9.95%	10.46%	11.09%
0.65	6.05%	10.28%	10.83%	11.51%
Average		9.95%	10.46%	11.09%

Note: Standard CAPM Formula = R_f + ß x (R_p)

As a check methodology, the above indicates a CAPM cost of equity range of roughly 9.65% to 11.50% with a midpoint of 10.60% prior to any adjustment for flotation costs. The range corresponding to BHE's estimated beta of 0.60 would be roughly 9.95% to 11.10% with a midpoint of 10.45% before flotation costs. As we will discuss later, we reject BHE's suggestion that it is necessary to raise our final ROE recommendation to account for what it contends is a 30 basis point increase in interest rates since the close of the record in this case. We note, however, that the 6.05% (30-year T-Bond) risk-free rate used in the table above is 25 basis points higher than the 5.80% shown in the Bench Analysis and, therefore, indirectly makes BHE's proposed adjustment.

7. Issuance Costs

a. Positions Before the Commission

BHE witness Strong recommends a 4.9% or 32 basis point (0.32%) flotation cost allowance. Dr. Strong bases his recommendation on a regression analysis he performed on the Oppenheimer/CIBC database for 77 non-IPO stock issues between 1996 and 1999. Dr. Strong found that the cost of a common stock issue is inversely proportional to the size of the issue. This would indicate that a small company like BHE would pay, on a percentage basis, higher issuance costs than a larger firm. Dr. Strong used his regression analysis and a hypothetical $20 million dollar stock issuance to arrive at a 4.9% flotation cost allowance for BHE. Staff pointed out at hearings that out of 77 Non-IPO issues, only 11 involved electric utilities compared to its own survey which included 13 electric utilities. The implication was that Dr. Strong's sample could be less directly applicable to the electric utility industry than Staff's sample.

Staff proposed that flotation costs be limited to 3.7%, or 20 basis points (0.20%), based on a survey of common equity issuance costs in the electric utility industry from 1994 to 1998. The Bench's survey covered all the electric utilities in the *Value Line* (Basic Edition) over this time period. Staff showed that for a hypothetical

$20 million dollar stock issuance, that 3.5% to 3.9% was an appropriate allowance for an electric utility. At hearings, Staff asked BHE to provide the amount of common equity it has issued since 1994 through its dividend reinvestment program (DRP). BHE subsequently provided data showing that roughly $3.7 million in new common equity was raised through its DRP program between January 1994 and September 1999.

The Public Advocate argued against a flotation cost adjustment. According to the OPA, flotation costs should only be allowed when future stock issuances are likely to occur and the OPA believes that BHE will most likely not be issuing new stock in the foreseeable future. In the event that the Commission approves a flotation cost allowance, the OPA recommends that the 20 basis point adjustment proposed by Staff be adopted rather than BHE's proposed 32 basis points.

b. Analysis and Conclusion

As was the case in *97-580*, we recognize that the issuance of securities is not accomplished without some costs and find it reasonable to compensate investors for them. Dr. Strong's analogy regarding the closing costs paid on a mortgage by a homeowner illustrates how these costs persist over the life of the loan in the form of a higher effective interest rate. Since we do not include an actual or even a normalized expense amount reflecting these costs in BHE's (or any other utility's) revenue requirement, it is appropriate to include the adjustment in the cost of equity. We recognize that in so doing we are essentially allowing a perpetual recovery of these costs. It is therefore imperative that we ensure that these costs are not overestimated. Based primarily on the discussion on pages 18-19 of the Bench Analysis, we will allow a flotation cost adjustment of 3.7% or 20 basis points (0.20%). We believe that the Bench Analysis provided the most directly relevant data regarding the equity issuance costs for electric utilities.

We do not question the accuracy of Dr. Strong's regression calculations, however, we cannot determine whether or not the stock issuances he considered were for companies of the same, higher or lower levels of risk than electric utilities. Although there are fixed costs involved with an issuance of securities, it is possible that low risk stocks (such as electric utilities) regardless of their size could expect to experience lower underwriting spreads, or variable costs, with their common stock issuances. Dr. Strong acknowledged this possibility and admitted that he did not investigate this further.

The Company's last open market common equity issuance was $14.7 million in June 1993 and was apparently done at a cost of 4.8% or roughly $705,000. Between January 1994 and September 1999 the total amount of common equity issued under the Company's dividend reinvestment program (DRP) was approximately $3.7 million. Dr. Strong stated at hearing that such a program would be a "pretty low cost" source of common equity for BHE if it did not involve selling shares at a discount from market price. Company witness Poulin confirmed that BHE's dividend reinvestment program has not to date involved a discounted share price. Adding the

$3.7 million in issued common equity from the DRP to the $14.7 million results in total common equity issues of $18.4 million since 1993. If the cost of the DRP issuances is assumed to be zero, $705,000 in issuance costs translates to about 3.8% of proceeds. The fact that BHE has a DRP in place and will continue to obtain some amount of new common equity in the future at a negligible cost, provides further support for the 3.7% increment we are adopting here. In the future we will continue to monitor both the cost of electric utility common stock issues and the use of DRP's by utilities. It is conceivable that an industry-wide movement toward the use of DRP's may eventually reduce or eliminate the need for a flotation cost adjustment.

8. Cost of Common Equity

The cost of equity recommendations for BHE range from the Public Advocate's 9.80% to the Company's 11.92%. The Bench Analysis developed a cost of equity recommendation of 10.75%, based on a range of 10.50% to 11.00%. We conclude that the proper cost of equity for BHE's post-divestiture T&D-utility lies within the range 9.70% to 11.70% with a midpoint of 10.70%, as indicated by the DCF analyses provided in the Bench Analysis adjusted as we discussed earlier. This is somewhat higher than the midpoint range of 10.45% to 10.55% suggested by the CAPM analysis we used as a check methodology in this proceeding. If we accepted the midpoint ROE estimate of 10.70% and allowed BHE to recover 20 basis points in flotation costs, we would arrive at an all-in ROE of 10.90%. We will, however, include a subjective upward adjustment of 10 basis points and allow BHE an all-in ROE of 11.00% at this time. We believe the economy in BHE's service territory is not as robust as that of southern Maine and that, psychologically, the 11.00% threshold may provide an additional measure of comfort for equity investors as we restructure.

We believe that the risk profile of a pure T&D-utility lies within a range bounded at the low end by water utilities and at the high end by existing integrated electric utilities. As was the case in *97-580*, our reasoning is based on the opinions of the investment community. In *97-580* and in this case, we have yet to see an opinion from the investment community that would suggest that pure T&D utility operations would be anything but less risky than fully integrated electric utility operations.

The Company's argument that our adoption of something other than its 11.92% cost of equity estimate would somehow fail to account for the true riskiness of BHE's T&D-utility is inaccurate. BHE's Brief devotes a fair amount of discussion of bond ratings of the peer groups used by the OPA and the Bench in this case. However, we noted earlier in our discussion that the OPA and Advisory Staff provided us with peer groups of utilities that bracketed the Mid Triple-B to High Single-A bond rating ranges. There is also considerable variation within the peer groups, for example, the Cluster Analysis peer group contains companies with S&P ratings as low as BBB-, while the Bond Rating peer group contained companies with S&P ratings as low as BB+. All indications from S&P are that BHE is somewhere in the BBB/BBB- bond rating range, which is covered by these peer groups. By allowing 11.00% in this case, we have chosen a number that is above the midpoints, medians or averages suggested by each of these two peer groups after we have adjusted for outliers. Therefore, the cost of equity point estimates suggested by these peer groups would adequately account for BHE's risk profile today.

The Company has also expressed concerns regarding the relative price to earnings (P/E's) and market-to-book (M/B's) ratios of the peer companies versus those for BHE. We do not believe such concerns are valid. Regarding P/E ratios, they are not particularly useful to us in cost of equity proceedings because it is often difficult to determine which "E" investors are trading on. Is it this year's forecast, next year's forecast, a five-year forecast or last year's actuals? Dr. Strong abandoned a P/E model in *97-116* for reasons including these. It is likely that future expectations are most relevant which complicates this even further in cases involving Maine utilities. Restructuring and divestiture has caused analysts to stop providing earnings forecasts as far back as a year ago, as we learned in *97-580*, and as happened again in this case.

Market-to-Book ratios are also not completely reliable indicators of cost of equity. The DCF formula of: $P = D_1 / K\text{-}g$, where P is the current price, D_1 is the forward dividend, K is the cost of equity and g is the dividend growth rate, shows that it is possible to have different stock prices and, thus, different M/B ratios while having the same cost of equity. All that is required is a different growth rate. BHE contends that since the peer groups have higher average M/B ratios than its own, that the dividend yields of these companies are somehow depressed, leading to lower DCF results. We believe that the peer group companies, in general, do not have yields that are artificially depressed. In fact, when we compare their yields to BHE's, we find that BHE's actual yields are lower than those of the peer groups as a whole. BHE's share price has been hovering in the $16.50 range since early July. With a $0.60 per share dividend raised by a hypothetical 5.0% growth rate, BHE's forward dividend would be $0.63 per share, or a corresponding forward yield of around 3.80%. Column 5 of Bench Analysis Exhibits COC-13 to COC-16 shows that average peer group forward yields are at a minimum 4.50% and are, therefore, not depressed relative to BHE's forward yield (assuming the 5.0% hypothetical growth rate for BHE). Incidentally, at a share price of $16.50 and a current dividend of $0.60, BHE would require a dividend growth rate of roughly 7.70% to reach the Company's recommended ROE of 11.60% before flotation costs. Dr. Strong noted on surrebuttal and at hearing that he believed that a growth rate of this magnitude was not realistic for BHE.

The Company made a number of suggestions in its Brief regarding risk premium type methodologies that the Commission should use to set an appropriate return for BHE. These included such things as adjusting for increases in interest rates, using CMP as a base and making subjective upward adjustments, and curiously, using our decision in *97-116* as a starting point. We agree with the OPA that it would be inappropriate for us to even consider these types of adjustments simply because these recommendations were brought to us after the record closed. There are additional reasons why we might reject such methodologies in any case. These include the fact that we have historically and categorically rejected risk premium-type estimation methodologies numerous times in the past, most recently in *97-116*. We do not believe it is appropriate to simply look at one indicator in isolation. Rather it is necessary to go through an entire analysis in arriving at a decision. Advisory Staff expressed this view quite clearly at hearings and we agree. On the whole we are satisfied that an ROE of 11.00 % properly captures the risk profile of BHE's T&D operations going forward.

9. Capital Structure & Weighted Average Cost of Capital (WACC)

a. Positions Before the Commission

From the standpoint of the total dollar amount at stake, the issue of capital structure in this case is relatively minor. The areas of disagreement are limited to the issue of whether or not a Short-Term Debt component should be included, and also whether or not it is appropriate to include certain unexercised common stock warrants associated with the PERC transaction in Common Equity. Company witness Poulin has proposed an average rate year capital structure of $319.34 million, comprised of 40.4% Common Equity, 1.5% Preferred Equity, 1.0% Short-Term Debt, 27.8% Long-Term Debt and 29.3% Ultrapower Debt. Public Advocate witnesses Kollen and Baudino support an alternate capital structure composed of 40.5% Common Equity, 1.5% Preferred Equity, 28.2% Long-Term Debt , 29.8% Ultrapower Debt and no Short-Term Debt. To calculate these proportions, OPA witness Kollen removed roughly $3.28 million in Short-Term Debt and $1.88 million in PERC warrants from Mr. Poulin's proposed capital structure, resulting in a total capital amount of $314.17 million.

The Bench Analysis surveyed the electric, natural gas LDC and water industries to determine a benchmark with which to compare the proposed capital structures and, generally, indicated that both proposals are reasonable for BHE. The Bench Analysis included the average actual capital structures of most of the *Value Line* universe of electric, water and gas LDCs for 1996, 1997, and 1998. These capital structures included capital leases and current maturities of long-term debt, but did not include any "off-balance sheet obligations" which would have had the effect of reducing the common equity ratios shown in Bench Analysis Exhibits COC-4, 5 and 6 across the board. No party disputed Staff's capital structure survey or provided data showing how the common equity ratios would be reduced if off-balance sheet obligations were included for all companies.

b. Analysis and Conclusion

In our Order in *97-580* we stated that generally speaking, capital structures are not determined by bond rating criteria or the stated goal of a company to achieve a certain rating. Instead, cost efficiency is the primary concern when determining a utility's appropriate capital structure. This means that the utility in question should resemble the majority of its industry peers so that it will be able to attract capital on reasonable terms. The evidence in this case shows that the electric utility industry is primarily rated in the Triple-B to Single-A bond rating range, and BHE's capital structure with a common equity ratio of roughly 40% is reasonable for a T&D-utility.

We will adopt the capital structure shown in the table below for BHE's T&D-utility which includes a Short-Term Debt component and excludes the unexercised warrants associated with the PERC transaction. We have included a Short-Term Debt component in the Company's capital structure, at this time, because the vast majority of utilities commonly employ Short-Term Debt in their capital structures. The OPA's position that BHE's Short-Term Debt should be rejected due simply to its high cost is not appropriate. BHE renegotiated its revolving credit line at an unfavorable time (following loan covenant violations) and paid accordingly. Besides paying a higher interest rate on outstanding balances, BHE must pay a commitment fee on unused "availability." This is common in the banking industry especially for companies in financial distress. The presence of the revolver was essential to the Company and its customers in the period following its emergency rate case in 1997. Therefore, it is not appropriate to penalize the Company for having this credit facility in place in the rate effective period.

Regarding the unexercised common stock warrants associated with the PERC contract restructuring, we agree with the OPA that these balances should not be included in the Company's common equity. There appears to be no accounting requirement stating that the warrants must be included in the capital structure for ratemaking purposes. As discussed in Section IV(C)(2), we have not included the unexercised warrants in rate base. Furthermore, while we acknowledge that we do not know with certainty what the warrant holders will do in the future, to the extent they exercise, a "cash option" is available to the Company and this appears to be BHE's preferred choice at this time. For these reasons, it is our opinion is that ratepayers should not pay for such a speculative adjustment at this time even though the cost would be relatively modest.

Therefore, we will use a capital structure comprised of 40.1% Common Equity, 1.5% Preferred Equity, 1.0% Short-Term Debt, 29.5% Ultrapower Debt and 27.9% Long-Term Debt. We also adopt the embedded cost rates recommended by the Company for Preferred Equity, Short-Term and Long-Term Debt. As shown in the table below, we find that BHE has an overall weighted average cost of capital of 9.28% and a pre-tax WACC of 12.37% for its non-Ultrapower ratebase using the Company's embedded cost rates as shown and an all-in cost of common equity of 11.00%.

Overall Weighted Average Cost of Capital

Capital Component	Percent of Total	Cost Rate	Weighted Average Cost of Capital	Pre-Tax WACC*
Common Equity	40.1%	11.00%	4.41%	7.44%
Preferred Equity	1.5%	5.65%	0.08%	0.14%
Short Term Debt	1.0%	13.27%	0.14%	0.14%
Ultrapower Debt	29.5%	7.49%	2.21%	2.21%
Long Term Debt	27.9%	8.74%	2.44%	2.44%
Total	100.0%		9.28%	12.37%

•Tax Rate is 40.8% per BHE (Poulin Surrebuttal Exhibit-P-SR-1-1 Revised)

E. Reconciliation of Certain Expenses

BHE has requested that certain expenses should be subject to deferral if reliable data is not available prior to the close of the record. Specifically, the category of expenses are:

- Maine Yankee decommissioning expenses
- Revenue from non-core customers
- Energy Conservation costs
- Regulatory assessments
- NEPOOL-ISO charges

As an initial matter, we note that ratemaking is generally prospective. A utility's future costs and revenues are projected using a historic test year with adjustments then made for known changes and attrition. Rates once established, remain in effect until changed. Reconciliation or deferral of costs is not a favored utility ratemaking approach in Maine, because reconciliation of projected to actual costs or the deferral of costs for later recovery reduces the incentives of utilities to act efficiently and to minimize their costs. In fact, the incentive ratemaking trend of this Commission has been to impose price caps to further remove the link between costs and rates so that additional incentives are created for utilities to appropriately manage their costs.

There are, however, circumstances in which the Commission should consider exceptions to its general ratemaking principles. For example, we allowed utilities to defer the ice storm costs, because of their magnitude and unusual nature. Additionally, in BHE's last case, we allowed reconciliation of Maine Yankee-related expenses, as part of its rate plan, to deal retrospectively with unknown decommissioning costs and any FERC prudence decisions.

Based on these general ratemaking principles, we will discuss below each category of expenses raised by BHE to determine if extraordinary ratemaking treatment is justified.

1. Maine Yankee Costs

A consensus developed that Maine Yankee decommissioning expense did not require reconciliation because of FERC ratemaking and the use of a Decommissioning Trust Fund. Instead, the parties focused on non-decommissioning expenses and payments into the Decommissioning Trust Fund.

In response to the Bench Analysis, BHE appeared to agree to remove certain non-decommissioning expenses from the stranded cost calculation of Maine Yankee costs, namely payments to Texas pursuant to the Low Level Waste Compact and payments to the State of Maine to repay the Spent Fuel Trust Fund. Neither of those payments are expected to occur in the two years before stranded costs are again investigated. In the event that BHE must reimburse Maine Yankee for either Low Level Waste Compact payments or Spent Fuel Trust Fund payments, BHE may defer such payments on its books until the next stranded cost investigation.

BHE also appears to seek authority to defer any change in the Maine Yankee decommissioning trust collections. Pursuant to the settlement of the most recent Mane Yankee FERC rate case, Maine Yankee must file a case at FERC that examines decommissioning rate issues for effect no later than 2004. A change in decommissioning collection rates is not expected before then.[15] In the unlikely event that FERC did allow an increase to Maine Yankee collection rates before the next stranded cost investigation, we would permit BHE to defer the amount of the FERC ordered change.

2. Revenue from Non-Core Customers

BHE proposes that, to the extent the renegotiation of certain special rate contracts is not completed in time to be reflected in rates, an estimate should be used to set rates and deferral allowed reflecting the actual amount above or below the estimate.

In considering BHE's proposal, we note that there are two categories of special rate contracts at issue. First, there are existing bundled contracts (i.e., contracts to provide both generation and delivery services at a bundled price) that extend beyond March, 2000. These contracts must be reformed because utilities are legally prohibited from providing generation services after March 1, 2000. In its last session, the Legislature provided explicit direction as to how these contracts should be

[15] In fact, according to Maine Yankee's decommissioning plan, no increase would occur in 2004.

handled. P.L. 1999, ch. 398, Part K (codified at 35-A M.R.S.A. § 3204(10)). Specifically, utilities are required to reform these contracts so that customers continue to pay the same total price for electricity for the remainder of the contract term. The utility has the responsibility to ensure that the customer used due diligence to obtain the lowest price for generation services from the market.[16] If so, the reformed T&D contract price would equal the difference between the original bundled contract price and the price for generation service. If due diligence was not exercised, the price would equal the difference between the original contract price and a reasonable market price for generation.[17]

The second category comprises current bundled contracts that expire prior to March 2000. These contracts were originally entered based on BHE's view that they were necessary to maximize revenues, either because the customers have cheaper alternatives (e.g., self-generation) or would reduce (or eliminate) purchases in the absence of a discount (e.g., reduce or eliminate manufacturing processes). Because these contracts expire prior to March, 2000, BHE must determine whether to offer such customers a discounted, T&D-only contract for the period after March 1, 2000. This decision requires BHE to re-evaluate the customers' alternative to buying electricity from the grid, as well as evaluating the price by which the customer could purchase electricity from a competitive supplier.[18]

The problem associated with both categories of contracts is their timing with the current ratemaking process. It may well be the case that BHE will not be able to complete negotiations with its customers in time for the contracts to be filed, reviewed, and incorporated into the March 1, 2000 T&D rates. BHE has been placed in the position of having to restructure its special rate contracts as a result of the legislative decision that utilities will no longer provide generation services. For this reason, BHE should not be harmed solely as a result of the timing of the transition to a competitive generation market as it relates to the current ratemaking process.

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[16] In its exceptions, BHE suggests that it does not have the responsibility to ensure the customer's due diligence in obtaining the lowest cost generation services. Rather, BHE argues that the Commission should "deal directly" with the customer to assure due diligence. We disagree. The statute clearly contemplates that the utility will renegotiate a T&D-only rate based on its assessment of the customer's due diligence in obtaining generation services. The Commission's role is to set a T&D contract rate if the parties cannot agree.

[17] As noted above, the Legislature requires the Commission to resolve disputes if the contracting parties cannot agree.

[18] We note that we recently revised CMP's pricing flexibility guidelines to be applicable in a restructured environment. *Order,* Docket No. 99-155 (July 13, 1999). We anticipate conducting a similar review of BHE's pricing flexibility guidelines in the near future.

The difficulty with either simply accepting the T&D contract rate for ratemaking purposes or adopting BHE's deferral proposal is that there is little incentive for BHE to aggressively act to maximize the revenue contribution from its special rate contracts.[19] Additionally, there may be little or no opportunity for a meaningful Commission review of the contracts prior to rates going into effect on March 1.

Accordingly, we adopt the following procedure regarding special rate contracts. No later than February 1, 2000, BHE must file its re-negotiated contracts (with supporting materials) or its then current view of the likely contractual T&D rates for situations in which negotiations are ongoing.[20] The Commission will conduct a summary review of the general reasonableness of the contractual T&D rates before accepting them for purposes of March 1, 2000 rates.[21] This summary review will not constitute a prudence evaluation. Instead, we will open a new proceeding to review the reasonableness of contract reformations shortly after concluding this proceeding. This review will be concluded within 6 months. For the first category of contracts discussed above, the review will only include BHE's evaluation of customer's due diligence in obtaining competitive supply. For the second category, our review will include BHE's evaluation of the customer's alternative to purchasing off the grid, in addition to cost of competitive supply of electricity taken from the grid. Consistent with the Commission Order in *97-580*, there will be a presumption that the bundled rates for contracts signed under the Company's rate plan (as distinct from its pricing flexibility plan) were reasonable, although the Company is under a continuing obligation to ensure that the costs of the Company's alternative still support the level of discount.[22]

If the review concludes that BHE acted prudently, the proceeding will end without consequence. In the event the review shows that BHE acted imprudently, we will act within our authority to keep ratepayers neutral to such imprudence. Thus, we may order that BHE set up an accounting vehicle to defer the revenue consequences of its imprudence for later recognition in rates. Alternatively, we may order an immediate reduction in T&D rates.

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[19] In the CMP rate proceeding, we noted CMP's continuing obligation to act to minimize discounts by re-assessing the then current situation when negotiating T&D-only rates. *97-580* at 37.

[20] We have chosen February 1, 2000 to allow for a summary review. BHE should file actual contractual terms as soon as negotiations are complete so that the actual contract terms can be used in setting rates.

[21] Any revenue delta sharing ordered by the Commission will continue to apply and will be incorporated into the March 2000 rates.

[22] A presumption will not exist for BHE's assessment of the customers' reasonable cost of generation services from the market.

We recognize that this approach is not ideal. Prudence reviews are generally difficult proceedings, often concluding with unsatisfactory results. However, this approach is the best way to proceed under the current circumstances. The existence of an after-the-fact prudence review and a possible cost disallowance should provide BHE some incentive to act to minimize rate discounts, as well as providing us with reasonable time to review the Company actions.

3. Energy Conservation Costs

During its last session, the Legislature revised the restructuring statute's provisions related to energy conservation. Under the current law, energy conservation funding levels will be set between .5% of the T&D utility revenue and 1.5 mills per kWh. 35-A M.R.S.A. § 3211(4). The statute specifically provides that the Commission shall include the cost of conservation programs in the rates of transmission and distribution utilities. 35-A M.R.S.A. § 3211(7).

At the hearing, BHE and the OPA stated their agreement that if the funding level is not established by January 20, 2000, BHE's revenue requirement will incorporate an energy conservation expense of 0.5% of its revenue requirement. If a different amount is established after January 20th, BHE may defer the difference between the 0.5% amount and the actual expense for later recovery.

We find the agreement regarding energy conservation to be reasonable and it is hereby adopted. In the restructured environment, ratepayer funding of energy conservation is solely a result of a legislative mandate in which the utilities have no control over the amounts to be expended or how the funds will be used.[23] For these reasons, the utility should not bear the risk of inadequate recovery and, thus, deferral of energy conservation expenses are justified.

4. Regulatory Assessment

BHE proposes that any special assessments related to restructuring be deferred for future recovery. As a general rule, a special assessment would be a reasonable candidate for deferral, because it is a governmental mandated one-time cost. However, we make no specific decision in this regard until presented with a request to defer a particular special assessment.

5. NEPOOL-ISO Charges

BHE states that, in Phase II of this case, the Commission should review the status of FERC's approval of certain NEPOOL and ISO charges to determine

[23] This is in contrast to the prior obligation of least cost generation planning under which utilities were responsible for obtaining the lowest cost mix or supply-side and demand-side resources to meet its customers needs.

whether they are sufficiently certain to be used for setting March, 2000 rates or whether a deferral mechanism is warranted.

Upon a request by BHE in Phase II, we will review specifically identified cost items to determine whether they should be included in rates or whether deferral would be appropriate.

IV. STRANDED COSTS

A. Overview

In this part of the Order, we address the issue of what amount of stranded costs should be included in rates. The Restructuring Act states that, at the onset of retail access, the Commission shall provide a transmission and distribution utility a reasonable opportunity to recover stranded costs. 35-A M.R.S.A. § 3208(5). A utility's stranded costs are determined by summing:

> 1. The costs of a utility's regulatory assets related to generation;
>
> 2. The difference between net plant investment associated with a utility's generation assets and the market value of the generation assets; and
>
> 3. The difference between future contract payments and the market value of a utility's purchased power contracts.

35-A M.R.S.A. § 3208(7).

The Act directs the Commission to rely on market information to the greatest extent possible when setting stranded costs, and to periodically review and correct substantial inaccuracies in the stranded costs of the non-divested assets. 35-A M.R.S.A. § 3208(2), (6). Pursuant to section 3204 of the Restructuring Act, investor-owned utilities are required, with certain limited exceptions, to divest themselves of all of their generation assets prior to the start of retail competition. For the generation assets and contracts not sold, 35-A M.R.S.A. § 3204(4) sets forth a process whereby BHE's rights to energy and capacity from these resources will be sold at periodic auctions. The prices received from these sales will provide market information upon which stranded costs can be based, and the periodic reselling of the rights will provide opportunities for regular review of the related stranded costs.

We discuss below BHE's stranded costs in light of the above statutory provisions.

B. Divested Generation Assets

1. Gain on Sale

In September 1998, the Company closed on its sale of the Graham Station site to Casco Bay Energy. That same month, pursuant to its divestiture plan filed with and approved by the Commission, the Company entered into a contract for the remainder of its generation assets, including the Company's interest in the MEPCO transmission line and the West Enfield Hydro project, with PP&L Global, Inc.

The Company in its rebuttal case estimated the value available to offset stranded costs from these two transactions as follows:

Gain on Sale of BHE Assets to PP&L	$28,042,419
Gain on Sale of Partnership Interest in Bangor Pacific (West Enfield)	$4,503,541
Gain on Sale of Graham Station	$4,413,823
Gross Gain on Sales	$36,959,783
Less: Selling and Closing Costs	(3,000,000)
Less: Cost to Retire Securities	(2,711,050)
Net Gain	**$31,248,733**

The Company closed on all aspects of the PP&L sale, with the exception of the West Enfield project, during the week of May 25, 1999. The West Enfield portion of the sale to PP&L closed during the last week of July 1999. The Company in its surrebuttal case revised its calculations of net gain on the sale as follows:

Gain on Sale of BHE Assets to PP&L	$25,756,292
Gain on Sale of Partnership Interest in Bangor Pacific (West Enfield)	$4,521,297
Gain on Sale of Graham Station	$4,389,750
Gross Gain on Sales	$34,658,339
Less: Selling and Closing Costs	(3,000,000)
Less: Cost to Retire Securities	(2,711,050)
Net Gain	**$28,947,289**

The major driver of the nearly three million dollar reduction in the net gain calculation was the Company's inclusion of $3,077,258 for Hydro Construction Work in Progress (CWIP) as a deduction to the PP&L gross sales price. At the hearings, the Company witness Dawes testified that these expenditures were related to the construction of the Veazie dam flashboard. Mr. Dawes was later contradicted by Company witness Lee who testified these amounts were for FERC hydro-relicensing.

As part of its Phase II filing, the Company should document where these CWIP costs are on its Company's books of accounts; what particular projects the costs were related to; and the dates that they incurred. For purposes of estimating stranded costs as part of this Order, we will retain the CWIP deduction from the PP&L sales price.

2. Interim Revenue Requirements

a. Overview

BHE's sale of generation assets prior to the start of retail competition significantly changes the Company's revenue requirements between the date of sale and the start of retail competition. In *97-580*, the Commission concluded that these interim revenue requirement impacts should be considered in the calculation of available value from the sale of assets and the stranded costs. To determine these impacts, it is necessary to (1) eliminate the costs associated with operation of the sold generation assets; (2) add the costs of replacing the power supplied by the sold assets; and (3) reduce the revenue requirement by the carrying costs to be applied to the available value account during the interim period.

In its direct, rebuttal and updated filings, the Company did not include any calculation of the interim revenue requirement impact of the early sale of its generation assets. In *Bangor Hydro-Electric Company, 1999 Rate Plan Annual Review,* Docket No. 99-097 (May 28, 1999), the Commission required the Company to file a plan for measuring the revenue requirement savings associated with the sale of its generation assets. In response to the Commission's directive in Docket No. 99-097, the Company filed its interim revenue requirement savings proposal on June 25, 1999. In that filing the Company estimated total savings to be $1,575,473. As part of the surrebuttal testimony, the Company revised its interim revenue requirement to a deficiency of $11,987. This change was principally a result of the Company's incurring extremely high replacement power costs for Wyman #4 during the month of June. On September 1, 1999, BHE submitted corrections to the interim asset sale savings calculation. The most significant aspect of the corrections was to eliminate Wyman #4 fuel as an expense savings item in the calculation. BHE noted that the savings were already captured in its calculation of Wyman #4 replacement energy because it calculated Wyman #4 replacement energy costs by using only the incremental amount by which the market price exceeds Wyman #4 fuel costs. Correcting for this error, and some other minor changes changed resulted in a $1,565,787 interim revenue deficiency.

The major components of the interim revenue requirement calculation are discussed below.

b. O&M Cost Savings

In our Accounting Order in this docket we allowed the Company to defer 50% of the A&G costs which would be allocated to restructuring wage expenses allowed by the Order. We noted that to the extent we found overheads related to restructuring labor costs as incremental and, therefore an allowable restructuring cost, we were likely to treat these costs as avoidable when calculating restructuring related savings. The Company did not include any A&G savings as part of its asset sale interim revenue requirement calculations in its surrebuttal testimony. As part of the Company's September 1, 1999 correction to its interim savings calculation, however, the Company stated that:

> In response to Examiner's Data Request No. 25, question 12, the Company agreed that 50% of the A&G overheads should have been included in the calculation of the interim savings calculation to be consistent with their inclusion in the determination of the deferred restructuring related costs. In the Surrebuttal filing, no A&G savings had been incorporated into the interim savings calculation. This amount, which is calculated in this data response, amounts to $74,569. Exhibit B/D-SC-2-9A has been revised to include A&G savings of $8,285 for each month in the period from June 1999 through February 2000.

The $74,569 of A&G savings was based on a 15.74% A&G allocation factor. Our Accounting Order in this case noted that the A&G costs would be allocated to the deferrable restructured expenses using the Company's 17.76% A&G allocation factor. When asked about this apparent discrepancy, Company witness Dawes testified that the Company had updated its allocation factors and 15.74% was the current factor being utilized by the Company.

We accept the adjustment for A&G savings proposed by the Company and modify our Accounting Order to correct the factor to be used in allocating A&G costs from 17.76% to 15.74%. There does not appear to be any other real disagreement with the Company's calculation of O&M savings which will result from the sale of its generation assets.

c. <u>Rate Base Savings</u>

The Company in its interim revenue requirement filing estimated the capital savings from the PP&L sale to be $2,512,723 and $40,310 from the Casco Bay Energy sale. The Company calculated the rate base savings by multiplying the net book value of assets retired by the average weighted cost of the securities retired with the cash proceeds from the asset sale. In its Bench Analysis, the Advisory Staff recommended that the rate base portion of the interim revenue requirement savings were $4,052,064 from the PP&L sale and $65,745 from the Casco Bay sale.[24]

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[24] The Advisory Staff in its Bench Analysis noted that these amounts were only estimates and would need to be updated to reflect actual closing dates and book costs at the time of the closings.

In setting rates for the Company, the Commission is required to allow the utility an opportunity to earn a fair return on the reasonable value of the property used, or required to be used in, its service to the public. 35-A M.R.S.A. § 303. Reasonable value of the property is based on the original cost less depreciation. At the time of the asset sale closings of the Company's asset sales to PP&L and Casco Bay the generation assets in question were no longer public utility property and thus should be removed from rate base. There is no disagreement between the Company and the Staff's Bench Analysis that the assets should be removed at their net book value at the time of the sale. The difference in the two positions is over what capital cost should be used to calculate the savings associated with the removal of the assets from rate base. For the reasons set forth below, we reject the approach suggested by the Company and adopt the approach recommended in the Bench Analysis.

First, as a general matter, the Company's methodology is inconsistent with our general approach to ratemaking which is done on a book basis. In the past, when we have allowed the Company to accrue carrying costs on its Allowance for Funds Used During Construction (AFUDC) balances, we have used the overall cost of capital as the carrying cost rate. The Commission did not, at such time, nor do we believe it is now appropriate to look solely at the incremental piece of financing used.

The Company, in its last rate case, was allowed a return on equity of 12.75% which resulted in an overall pre-tax cost of capital of 12.19%. In setting the Company's rates, this overall pre-tax cost of capital was applied to the Company's rate base which included the generation assets sold to PP&L and Casco Bay. It seems only logical that when the assets are removed from rate base, the revenue requirements effect (or return on) be based on the same rate. We would note that while CMP in *97-580* did ask for carrying costs on the gain account to be calculated in a fashion similar to BHE, neither CMP nor MPS in their stranded cost cases requested that when its generation assets were removed from rate base they be removed at anything other than the current overall pre-tax cost of capital.

Finally, we believe that the Company's approach, which tries to measure the incremental savings, does not in fact truly measure such incremental savings. A company's overall cost of capital is a function of its cost of debt, capital structure and its cost of equity, which is related to the first two factors. The Company's approach attempts to measure the incremental capital impacts by looking at the retirement of debt in isolation. It ignores the impact that the retirement has had on the Company's capital structure, level of risk and overall cost of capital. The Company's asset sale has decreased its overall risk and strengthened its balance sheet. These factors have been reflected in the Company's stock price increases since the asset sale but are not reflected in the Company's calculations.

As part of the Company's surrebuttal case, Company witness Poulin estimated the incremental equity savings to be only $260,000. Mr. Poulin's calculation relied on a 12.34% equity rate, which was arrived at by taking the average of the three ROEs recommended in this case, and then taking one-fourth of the difference between that rate and the 12.75% rate established in *97-116,* multiplied by the Company's pre-asset sale equity ratio. We find two major flaws with Mr. Poulin's estimation methodology. First, we believe that in looking at the equity-related savings resulting from the asset sale and related debt buy-down, the post-sale capital structure of 40% should have been used. Second and more importantly, we find that Mr. Poulin's division of the equity savings by four, based on his assumption that the Company was one-fourth of the way to the "less risky environment" of the T&D only utility, was erroneous and significantly understates the savings. The sale of the Company's generation assets at an amount considerably above book value is the defining event in transforming the integrated utility to a less risky T&D utility. We therefore conclude that the calculation does not provide a basis to either reject the approach proposed in the Bench Analysis or as a means of adjusting the Company's approach so that it fully measures asset sale capital savings.[25]

d. Transitional Power Supply Costs

BHE's transition supply calculations at this point are still based on estimates of replacement power costs for July 1999 through February 2000, rather than actuals. BHE should update its asset sale interim savings/cost calculation later this year or in early 1999.[26]

We find BHE's method of calculating transitional power supply costs to be generally reasonable. However, we will review in detail the calculation BHE submits in Phase II based on actual replacement power purchases. For example, in workpapers we have reviewed for June actual purchases, BHE uses $26.86/MWh as the fuel cost of Wyman #4. BHE should update Wyman #4 costs based on actuals during the period, or based on estimates of Wyman #4 fuel costs that track actual oil prices during the period. In addition, BHE remains obligated to minimize the cost of any replacement power it must procure. We will review BHE's efforts in this regard as part of the Phase II proceeding before determining the appropriate amount to apply to the asset sale proceeds.

e. Carrying Costs on Stranded Gain Account

Because BHE was able to sell its assets to PP&L and Casco Bay Energy at a gain prior to the time of retail access, the Company will have on its

[25] If we were to use the approach suggested by the Company, we would subtract the equity rate which we have established in this case, 11.00% and subtract that rate from the 12.75% rate, established in *97-116,* without dividing the result as suggested by Mr. Poulin. We would also use the post asset sale equity ratio. Adding these savings to Company's incremental debt savings actually results in greater net savings then the amount recommended by Staff.

[26] BHE's calculation of replacement power costs based on increased costs for the month of June by $1.47 million.

books a regulatory liability from the time of the closings through the date new rates go into effect for the Company. Similar to its recommendation regarding the calculation of rate base savings the Company has also recommended that the carrying costs on the regulatory liability resulting from the asset sale be calculated by using the weighted average cost of debt retired with the cash proceeds. Again, here the Advisory Staff recommends that be done on a book basis using the Company's overall cost of capital established in its last rate case. Based on its methodology, the Company estimates the carrying costs to be $1.76 million while the Advisory Staff in the Bench Analysis estimated carrying costs to be $1.93 million. Again, we reject the Company's position.

We would note that in the past when we have allowed the Company to create regulatory assets between rate cases, we have allowed the Company to accrue carrying costs in its favor at the overall cost of capital. Maine Yankee decommissioning costs and the Ice Storm recovery costs are relevant examples of our application of ratemaking principles. The Company argues that the regulatory liability created by the asset sale was extraordinary in size and, therefore, past ratemaking principles are inapplicable.

While restructuring is certainly an extraordinary occurrence, the size of the regulatory liability created by the sale of the Company's generation assets does not appear to be extraordinary when compared to other regulatory assets on the Company's books, e.g., the PERC contract restructuring ($21M); Beaverwood QF Buyout ($18M); and Seabrook ($30M); all of which will be recovered from ratepayers as stranded costs.

The Company argues that its approach to calculating carrying costs is not unique since in the past, as part of the fuel clause, the Commission would calculate the carrying costs on fuel clause balances on the basis of the short-term debt rate. We acknowledge the Company's point that an approach similar to the methodology they advocate using here has been used in the past. The debt tracking mechanism of the fuel clause, however, was part of an overall procedure which attempted to track and reconcile costs. As we previously noted, we view the retroactive dollar tracking provisions of the fuel clause to be a deviation from normal ratemaking and one which did not produce equitable results. We thus would not view past fuel clause accounting as a model for ratemaking in the future.

The Advisory Staff recommended that we base the carrying cost on the overall pre-tax cost of capital of 12.19% established in Docket No. 97-116, BHE's last rate case. This approach differs slightly from the one used in the CMP stranded cost proceeding where we used the overall pre-tax cost of capital established in the current stranded cost case as the carrying charge. Docket No. 97-580, Order at 99. In our Order on Reconsideration in Docket No. 97-580, we noted the cost of capital essentially can be seen as the rate charged for the use of money between rate cases. Although the Commission decided not to modify its decision, it noted that a strong argument could be made to use the cost rate set in CMP's last rate case (12.63%) rather than the 12.22% established in the stranded cost rate case should be used in calculating the carrying costs on the available value prior to the date new rates became effective. Docket No. 97-580, Order on Reconsideration, Order at 9 (June 22, 1999). Because the asset sales giving rise to the regulatory liabilities in this case occurred prior to our setting a new cost of capital for BHE, we believe it is appropriate to use the 12.19% cost rate set in Docket No. 97-116. Using the overall cost of capital of 12.31% would have the effect of slightly increasing the carrying costs.

As part of its Phase II filing, the Company should calculate its interim rate base savings and carrying costs on the available value based on the methodology proposed by the Advisory Staff and its actual book balances based on the closing dates of the asset sales.

C. Intangible and Regulatory Assets

1. Sale of Air Emission Allowances

a. Positions Before the Commission

In the Bench Analysis, the Advisory Staff recommended that the revenues received from the 1997 sale of emission allowances be considered a regulatory liability to reduce stranded costs. This recommendation was based upon the direction given by the Federal Energy Regulatory Commission on March 31, 1993 in Order No. 552, Docket No. RM92-1-000. This docket addressed the accounting treatment for emission allowances and included instructions for the treatment of any gains or losses on the sale of these allowances. The order required public utilities to defer gains on the sale of emission allowances in Account 254, Regulatory Liabilities, where “uncertainties” existed as to the ratemaking treatment.

The Company disagreed with the Advisory Staff’s position for the following reasons:

(1) This is not a regulatory liability at all much less a regulatory liability created by restructuring.
(2) It involves “cherry-picking” small revenue items while ignoring large expense items that occurred in the same year.
(3) There was not “uncertainty” as to the treatment of the emission allowances.
(4) This Commission, by accepting the FERC’s accounting of this particular item, “gives up” its ratemaking authority of this issue.
(5) FERC’s accounting policies, if followed, would lead to confusion in administering GAAP.

b. Decision and Analysis

The Company has taken exception with the Staff’s determination that there was uncertainty in the rate treatment of emission allowances because the Commission did not make any determination specifically requiring the Company to flow-back these revenues to the ratepayers. The fact that the Commission did not raise this issue prior to this proceeding does not itself mean that there was certainty or that the Commission agreed with the Company's accounting for this transaction. The Restructuring Act was passed in 1997, the year of the sale. The legislation provides the Company with an opportunity to recover its generation related stranded costs. However, it also requires utilities, such as BHE, to use their best efforts to mitigate stranded costs. The sale of assets, such as emission allowances, certainly is one way to mitigate stranded costs. The Company should have at a minimum recognized this possibility and at a least come to the Commission for clarification. Further, the Company does not provide any evidence that the Commission would allow it to keep revenues generated from the sale of ratepayer-funded assets.

The Commission has accepted the use of the FERC Uniform System of Accounts for use by the electric utilities in the State of Maine. The Order referenced included revisions to that system to allow for proper accounting of Emission Allowances, a new asset created by the actions of the Congress in the Clean Air Act. By requiring companies to follow the accounting direction of the FERC, the Commission does not give up its regulatory rights. In this case, the FERC stated that the rulemaking was to be rate neutral. In other words, the State commissions could and should determine the appropriate ratemaking treatment of allowances. As far as the requirements of GAAP, it is true that the actions of a regulator will determine whether a regulatory asset or liability exists. But GAAP does not decide the ratemaking treatment for any item and we believe that it is not an issue here.

In this case, the Company has stated that there was no uncertainty of the potential treatment and therefore, no regulatory liability exist. We disagree. Uncertainty did exist and the Company should have requested direction in the proper treatment of the gains from the sale. Furthermore, we believe that the particular asset was generation related and should be used to mitigate stranded costs. Therefore, we conclude that the $333,328 gain from the sale of emission allowances be included in the asset sale gain account and treated as a reduction in stranded costs.

The Company has stated that the Staff, by selecting this particular item, is cherry picking items out of the test year that benefit the rate payers while ignoring the negative items that happened during the same year. We do not disagree that these revenues would not likely recur. However, that is not the reason for the adjustment. If the gain had been accounted for properly, then the test year adjustment would not have been necessary as the gain would have been deferred instead of being reflected in income.

2. Treatment of PERC Warrants

The Penobscot Energy Recovery Company (PERC) restructuring costs result from an agreement with the Company that was entered into to lower the Company's costs related to its purchase power agreement with PERC. Under the agreement, PERC restructured its existing bonds and extended its debt maturity. BHE agreed to pay certain amounts to PERC over the life of the agreement and also issued stock warrants to PERC. Combined these costs equal the PERC restructuring amounts deferred on BHE books and reflected in rates.

We address four items in this section. The rate base treatment of unexercised warrants; the OPA's recommended adjustment to remove the amortization of unexercised PERC Warrants from revenue requirements; the treatment of the amortization of PERC restructuring costs for the period February 13, 1998 to June 26, 1998; and the treatment of the additional PERC restructuring costs.

a. Rate Base Treatment

In the Bench Analysis, the Advisory Staff recommended that the Company remove from rate base the estimated cost of unexercised PERC warrants and update cost of warrants exercised to ensure that the ratepayers do not pay a return on costs that have not yet been incurred. In its surrebuttal testimony, the Company agreed with the Advisory Staff that it is not appropriate to include an amount in rate base for warrants which have not yet been exercised. Since there are no objections, we will adopt the Bench Analysis recommendation and not include in rate base any amounts related to the unexercised warrants.

b. PERC Warrant Amortization

The OPA has recommended that we not include in rates the amortization of the PERC warrant costs for two reasons. First, there is no "cost" for the warrants as the Company has issued the warrants and only recorded a balance sheet transaction. Second, since the warrants have not all been exercised, the value is not known and measurable and there is no guarantee that the warrants will be exercised. As a result, any amounts included in rates would not be accurate.

The Company has disagreed with this recommendation. The Company states that the suggestion that the warrants would not be exercised is not credible given the gap between the exercise price and the current market price of the Company's common stock. It agrees that the exact timing and price of exercise are not known but believes that there is sufficient information available to determine a value and include the amortization in this rate period. In addition, the Company comments that not to allow the amortization currently would violate principles of intergenerational equity since future customers would be required to pay for current savings accruing under the PERC contract restructuring.

We agree with the Company. The fact that exact value and exercise date of the warrants is not known is not reason enough to ignore the intergenerational inequities that would exist if we deferred the amortization to later periods instead of allowing amortization in the periods where the savings from the contract restructuring are being recognized. Requiring the Company to account and adjust for any differences between the amounts in rates and the actual exercise value will provide ratepayers with protection in case the warrants are either not exercised or are exercised at a much lower value than estimated.

Therefore, we will reject the OPA's proposal and allow the amortization of the warrant costs to be included in the current rates with a provision that the PERC account will be adjusted to reflect actual warrant costs at the time of exercise. The Company should include the effect of any deferred differences in subsequent rate proceedings.

c. Amortization of PERC Restructuring Costs

In its surrebuttal testimony, the Company has requested that we reconsider an accounting order issued on January 13, 1999. The accounting order required the Company to begin amortizing the $1 million recognized in rates for PERC restructuring costs beginning on February 13,1998, the date rates were effective in Docket No. 97-116. The Company believes that the amortization should not begin until June 26, 1998, the date the PERC restructuring transaction closed. The Company believes that since the rates effective February 13, 1998 included the savings from the closing, the amortization should not begin until those savings are realized.

Under typical conditions, the amortization of a cost for book purposes should begin on the date that amortization is reflected in a utility's rates since that is the date that ratepayers begin paying the new rate. However, the PERC restructuring transaction was not typical due to its size and the integrated nature of the costs and savings. The rates reflected both the amortization and savings that resulted from the PERC restructuring transaction. The savings could not begin until the transaction was closed and as a result, the Company did not benefit from the savings although such savings were included in rates. To require the amortization of the costs during the pre-savings period would penalize the Company for events outside of its control.

Therefore, we will allow the Company to begin amortizing the PERC restructuring costs on June 26, 1998, the date the PERC restructuring contract closed, instead of on February 13, 1998, the date the rates in Docket No. 97-116 were effective.

d. Additional PERC Restructuring Costs

The Bench Analysis noted that the Company had increased the amount requested for PERC restructuring due to additional costs incurred and questioned the inclusion of those amounts, as there was no description other than "certain costs." Upon further review of the detail provided by the Company, it appears that the $105,000 of additional restructuring costs for a late received invoice from the Municipal Review Committee (MRC) and a January payment to PERC in final settlement of expenses incurred by the three parties (MRC, BHE and PERC) in connection with the contract restructuring were prudently incurred and therefore appropriate. We will allow the Company to include these additional costs in its PERC Restructuring Costs.

D. Tax Related Issues

Under normalization accounting principles, a utility includes in its regulated rates an amount for income taxes calculated as if the book lives of its plant in service were used to determine depreciation expense. On a utility's actual tax return the depreciation deduction is based on the Tax Code and IRS Regulations, which generally use much shorter lives for the assets. This results in a higher amount for depreciation for tax purposes, and consequently, lower taxable income and lower tax expense.

The Tax Reform Act of 1986 (TRA 86)created Excess Deferred Income Taxes (EDITs) by lowering the tax rates on corporations, including utilities. Due to normalization principles, a portion of the deferred taxes (due mainly to accelerated tax depreciation) on the books of utilities became "excess," because those tax amounts were collected from ratepayers (but not actually paid to the IRS) when the tax rates were higher. Had the tax rates not changed, the deferred taxes simply would have been returned to ratepayers over the regulatory lives of the assets, in accordance with normalization accounting principles.

Congress, in TRA 86, prohibited regulatory commissions from flowing back the benefits of the EDITs any faster than over the book (i.e., regulated) lives of the underlying assets that gave rise to the deferred taxes. Utilities claimed that any faster flow back would seriously harm their ability to continue to invest in new plant, and that ratepayers would receive the full benefit, including interest, of the excess taxes over the lives of the plant.

A similar situation exists with Unamortized Investment Tax Credits (ITCs). Although TRA 86 phased out this tax benefit, previous tax laws required that utilities flow back to ratepayers the amount of the ITCs no faster than over the regulatory lives of the underlying assets, but without even any interest. Like EDITs, utilities claimed that their ability to invest in new plant would be hurt by any other flow back, and again that ratepayers would eventually get the benefits (but without the time value of money) over the book lives of the plant.

At the time of its asset sale closings the Company had on its books of account $750,000 in Investment Tax Credits (ITCs) and $750,000 in Excess Deferred Income Taxes (EDITs). In Docket No. 97-580, when faced with this issue, we held that:

> There is no doubt that absent federal tax laws requiring a contrary result, appropriate ratemaking principles and the equities involved would lead us to conclude that the ITCs should be returned to ratepayers through the available value calculation at the time of the sale of the generation assets. In all of the PLRs of which we are aware, however, the IRS

> has consistently held that the federal Tax Code mandates that when public utility property is removed from service for any reason, including sale, the related ITCs and EDITs cease to exist on the regulated books of account of the utility.
>
> While we believe the conclusion reached consistently by the IRS in its PLRs is unfair and unjust from a ratemaking standpoint, we would not want to jeopardize the Company's ability to claim accelerated depreciation or cause CMP to incur substantial additional tax liabilities because of a decision on our part that runs contrary to the Tax Code, as interpreted by the IRS.
>
> Although equity and sound regulatory policy would lead us to conclude that CMP should be required to return its unamortized ITCs to ratepayers at the time of the sale of its generating assets, we are reluctant to risk the severe tax consequences that might ensue. Thus, we require CMP to seek a Private Letter Ruling from the IRS on the subject.

Initially, the Company argued that it should be allowed to retain the EDIT and ITC benefits since a flow-through would result in a normalization violation finding. The OPA argued that a flow-through would not constitute a violation and therefore the EDIT and ITCs should be flowed through. The Advisory Staff's Bench Analysis recommended that BHE's ITC and EDITs be placed in a suspense status awaiting the outcome of the CMP PLR process. In their briefs, the parties both seemed to accept the recommendation set forth in the Bench Analysis.

We agree that BHE's EDITs and ITCs should be retained on the Company's books until the PLR issue is finally decided. In *97-580*, we indicated that the Commission might seek redress through Congress or the courts if the IRS ruled adversely. We would not necessarily view the IRS's action on the CMP PLR request as the definitive and final word on this issue. Obviously, to the extent that this matter is litigated in the courts, BHE would receive notice of such action and would be able to participate fully as an affected party.

E. <u>Non-Divested Generation Assets</u>

1. <u>QF-related Stranded Costs</u>

BHE has six purchased power agreements with qualifying facilities (QFs). All six agreements have terms that extend well beyond the rate year. The term and output of QF agreements are summarized below:

Facility	Capacity (MW)	Contract End Date
PERC Solid Waste	21.93	2018
West Enfield Hydro	19.10	2024
Sebec Hydro	0.90	2025
Pumpkin Hill Hydro	0.85	2017
Milo Hydro	0.66	2014
Green Lake Hydro	0.40	2024

BHE projects the rate year costs for these QF contracts to be $24,658,000. BHE estimates the associated stranded costs to be $18,392,000 based on an assumed market value of $28.00/MWh.

BHE's cost estimates for these contracts appear reasonable except in one relatively minor regard. BHE estimated future QF contract prices based on an assumed inflation rate of 3% per year. BHE should update the prices in Phase II to reflect actual inflation to-date and then-current projections for future periods.

The stranded costs associated with BHE's QF contracts should be calculated using the same basic approach the Commission specified for Central Maine Power Company's QF-related stranded costs. Docket No. 97-580, Order at 65-66, 107. Using this approach, the stranded costs would be the difference between estimated contract costs and the amounts BHE receives when it sells its entitlements pursuant to Chapter 307 of the Commission's rules. For PERC, the cash distributions BHE receives under the three-way agreement entered as part of the 1998 restructuring of the contract should also be included. BHE does not disagree with this basic approach.

In Docket No. 97-580, the Commission found that QF-related stranded cost charges should reflect the same time period as the entitlement sales. Assuming BHE will sell its entitlements in a manner generally consistent with Chapter 307, we see no reason to treat BHE's QF-related stranded costs differently. The Commission would set stranded cost charges based on the initial sale period and sale prices, and then review, and, possibly, adjust charges when the next entitlement sale occurs. Thus, in this case, BHE's QF-related stranded costs should reflect the initial entitlement sales period, for example the two-year period required by Chapter 307.[27]

2. Graham Station Units and Land

In its calculation of available value from its asset sales, the Company has estimated a loss on the Graham units of $586,742 which was used to reduce the Asset Gain Account. This was calculated by using a "placeholder" sale "guestimate" price of $500,000. At the present time, the Company has not yet sold its Graham Station generating units and a sizeable portion of the land at the Graham

[27] The Commission may want to consider different approaches if BHE sells entitlements for substantially different time periods than contemplated by Chapter 307.

Station site. At this time, we will not reduce the Asset Gain Account based on the guestimate sales price.

The Restructuring Act requires investor-owned utilities to divest their generation assets by March 1, 2000. An investor-owned utility may apply for an extension of the March 1, 2000 deadline if the extension would likely improve the sale value of the assets on the market. As part of its Phase II filing, the Company should submit a request for extension for divestiture of these assets along with an updated plan for their sale. If these assets are not sold prior to the end of the Phase II proceeding we will include the full value of these assets in stranded cost rate base. When the assets are sold the Company can make the appropriate adjustment to the Asset Sale Gain Account. Like other stranded cost mechanisms we adopt here, this mechanism will protect ratepayers and shareholders from over and under-recovery of stranded costs.

F. Maine Yankee Expenses

The OPA suggests that money received by BHE in 1999 pursuant to the FERC rate case settlement, which included a retroactive refund of the reduced cost of equity back to the FERC-acceptance date (January 14, 1998), as well as payments to BHE by municipal contract customers, should be amortized over a 4-year period and calculated into BHE's revenue requirement.

The OPA's adjustment appears to be unnecessary. As the Company has stated in response to data requests, both the return on equity refund and the payments from municipal customers will be reflected in BHE's calculation of its deferred Maine Yankee expenses.[28] Thus, BHE's T&D revenue requirement will be calculated so that ratepayers receive the benefit of both the return on equity refund and the payment from the municipal customers in settlement of the FERC cases.

G. Stranded Cost Rate Setting Methodologies

35-A M.R.S.A. § 3208(6) provides that the Commission shall set stranded cost changes at least every three years. Since a large portion of stranded costs relate to QF contract obligations, we concluded in Docket No. 97-580 that our periodic stranded cost review should be coincident with the sale of QF output which is set to occur every 2 years pursuant to Chapter 307 of our Rules. Since CMP's costs were expected to decline over the 2-year period, we stated that rates should be calculated on a levelized 2-year present value basis. *97-580,* Order at 107.

In the case currently before us, BHE has recommended, given the uneven cost pattern of its stranded costs, amortizing its Asset Sale Gain Account in an uneven manner. Based on our decision in *97-580*, the Advisory Staff indicated in the Bench

[28] Pursuant to the last BHE rate case and the incentive rate plan instituted as part of that rate case, BHE defers and reconciles actual Maine Yankee expenses and replacement power expenses with the estimated amounts set in rates.

Analysis that the Company should submit a levelized stranded cost forecast as part of its reply to the Bench Analysis. In its Reply to the Bench Analysis Company witness Jones testified that the Company opposed the levelized approach since it would not provide the Company with adequate cost recovery and that stranded costs rates should be calculated like all other costs on a rate effective year basis.

At the hearing, the Advisory Staff, upon questioning from the Company's counsel, indicated that upon further reflection, the Advisory Staff believed that the Company's amortization approach achieved the objectives of the levelized approach (rate stability and appropriate cost recovery) and avoided some of the accounting complexities which accompany the levelization methodology. The Staff indicated that it was agreeable to such a methodology, however, the costs which are to be recovered in rates should be based on a two-year projection rather than a test year or single rate year basis. The Company in its Brief indicated that there no longer seemed to be disagreement on this issue.

We believe the approach set forth by the Advisory Staff at the hearings of basing stranded costs on a two year forecast and using the Company's uneven Asset Gain Account amortization to achieve our goals of rate stability and appropriate cost recovery adequately protects the Company's shareholders and ratepayers from under- or over-recovery of costs. We, therefore, adopt this approach and will calculate the Company's stranded cost charges based on this methodology in Phase II of this proceeding.

V. COST ALLOCATION AND RATE DESIGN

A. Top Down Methodology

1. Positions Before the Commission

BHE proposes that a top-down methodology be used to allocate the revenue requirement reduction resulting from the removal of generation costs (generation-related reduction) among its customer classes. Under this approach, the reduction from current bundled rates to T&D-only rates is based on each class's relative generation-related costs. To determine the classes' relative generation costs, BHE proposes to use the results of its Chapter 307 QF capacity and energy auction. Under this method, relative class generation costs are determined by multiplying the kW and kWh bid prices by each class's applicable units (i.e., class CP plus a reserve margin and energy usage, respectively).

In the Bench Analysis, the Advisory Staff supported the use of a top-down methodology, but expressed concern with BHE's proposed use of the Chapter 307 auction results. The Advisory Staff stated a preference for using the results of the standard offer bid process to allocate the generation-related reduction. In the Staff's view, use of the Chapter 307 results could be problematic because they may not accurately measure the separate market values of both capacity and energy. Measuring the market value of capacity and energy separately is important so that each class's relative generation cost responsibility can be determined. Although the Chapter 307 bidders are required to separately state a bid price for capacity and energy, they do not actually compete for the two components as separate products. As a result, their separated bids may not reflect the actual value of each component (although they would presumably reflect the value of the components combined.)

BHE responded that there is no reason to expect that the separated bid prices would not reflect the bidders actual view of the market value of each component. Additionally, BHE stated its concern that the standard offer bids may include costs that are not a good proxy for allocating the generation-related reduction. Specifically, BHE cites the possibility of inclusion of administrative costs that might not accurately reflect the classes' relative share of generation costs. A final concern is that the standard offer bids do not distinguish between subclasses taking service at different voltage levels, requiring some judgment in using the standard offer prices in implementing the top-down methodology.

The OPA supports the use of a top-down methodology and argues that the standard offer prices should be used rather the Chapter 307 bids. The OPA views the standard offer as preferable because use of the Chapter 307 bids would require additional manipulation to derive allocation factors for demand and energy and then an allocation of costs to customer classes. Additionally, the OPA views the Company's concern regarding administrative costs in the standard offer prices as misplaced because such costs are necessary to provide generation service and are thus generation-related.

In its Brief, the OPA argues that the top-down methodology should be modified because it implicitly assumes that the entire difference between current rates and the T&D-only rates consists of generation-related costs. The OPA states that not all of the overall cost reductions likely to occur are generation related. Rather, some decrease in T&D-related costs is likely as a result of declining capital costs and customer-related costs. As a consequence, the OPA states that residential ratepayers will be unduly penalized because they pay a relatively higher share of T&D-related costs. To address this issue, the OPA suggests two alternatives: 1) reduce current rates by an equal percentage across the board; or 2) subtract the cost of market generation from current rates and, if there is a net gain to be distributed, allocate the remaining reduction in proportion to the classes' T&D revenue requirement.

The IECG's view is that a top-down methodology should not be used to allocate the generation-related reduction among customer classes. Rather, the allocation should be based on an examination of the underlying T&D costs. The IECG, however, recognizes the Commission's precedent in this regard and argues for a full examination of costs and rate design in the near future.

2. Analysis and Conclusion

In our Order in the CMP proceeding, we adopted the top-down methodology for allocating the generation-related reduction among customer classes. We explained that this method to rate-setting will best fulfill our objective of designing T&D rates that facilitate a smooth and successful transition to retail access, because it is equitable, understandable and will minimize adverse bill impacts concurrent with retail access. *97-580* at 113, 116-119. Essentially, the top-down method removes generation-related costs from current rates in proportion to the amount of generation costs that are currently included in the rates of each customer class. Because costs are taken out of rates in proportion to the costs that are included in rates, the method has both a cost basis and is equitable to all classes of ratepayers. In addition, the top-down method should reduce customer confusion and controversy by essentially maintaining current rate structures and class allocations. It also reduces the potential for significant disparate bill impacts among customer groups by removing generation costs based on the relative costs of purchasing generation in the new markets.[29] For these reasons, we adopt the top-down methodology in this proceeding as we did in the CMP proceeding.

In the CMP proceeding, we stated that the standard offer prices would provide the basis for the top-down reduction. *Id.* at 119. We are not persuaded that the Chapter 307 auction results provide a conceptually superior means to implementing the top-down method. We reject BHE's argument that use of the

[29] As we mention below, this would especially be the case if the standard offer prices are used to implement the top-down method.

standard offer is flawed due to the possible inclusion of differing levels of administrative costs in the standard offer class prices that may not be included in current rates. Because differing levels of administrative costs are incurred to provide generation services to different customer classes, it is appropriate to recognize their existence when allocating the generation-related reduction. In fact, the possibility that standard offer bids may reflect differing administrative costs among classes is an attribute that makes use of standard offer prices preferable to using the Chapter 307 results. We do, however, agree with BHE that a downside of using the standard offer prices is that there may need to be adjustments, such as for voltage level. Finally, we recognize as valid the Staff's concern that the Chapter 307 bids may not reflect the separate market values of capacity and energy. Although bidders are required to state separate bids, it is the combined value that will determine the winning bidders. If, for example, a bidder prefers to pay for the QF output on a kWh basis, it could bid $0.00 for capacity. Under such a scenario, use of the QF bids would not be appropriate for the top-down method.

Of the two approaches, we continue to prefer the standard offer as a more straightforward measure of relative class generation costs. Use of the standard offer prices also has the benefit of minimizing disparate customer bill impacts for those customers that take standard offer service. However, we agree with BHE that both the standard offer bid process and the Chapter 307 auction are being conducted for the first time in a relatively new market and, as a result, it is sensible to review the results of both processes before a final decision is made. We will make this final determination in Phase II of this proceeding.

Finally, we reject the OPA's alternatives of using an equal percentage reduction, or subtracting market costs from current rates and allocating any residual in proportion to T&D revenue requirements. In concept, the OPA may have a point that some portion of the revenue requirement reduction could be due to lower T&D costs. However, there is no means to determine on the record in this proceeding whether this is indeed the case and, if so, the actual amount of the reduction that corresponds to lower T&D costs. In fact, it could even be the case that the revenue requirement reduction would be even larger but for higher T&D costs. We do know that the vast majority of the reduction results from the Company ceasing the provision of generation services. For this reason, it is appropriate to allocate the reduction based on the relative cost of providing generation services to the customer classes.

B. Rate Design Proposals

1. Positions Before the Commission

BHE proposes three specific changes to its intra-class rate design: 1) higher customer charges for non-residential classes; 2) removal of seasonal differential in rates; and 3) removal of time of day differential in rates.[30] BHE's view is that these changes would more accurately reflect the cost of service. Although the

[30] BHE does not propose inter-class re-allocation of costs in this proceeding.

Company understands the concern regarding negative bill impacts, it would like to make these changes as soon as possible, and proposes to, at least, remove the shoulder rate from the time of day rates.[31]

The Advisory Staff, in its Bench Analysis, responded to these rate design proposals. The Staff indicated general agreement to increasing non-residential customer charges closer to their marginal costs, as long it would not violate the "no losers principle.[32] The Staff stated its view that this would likely be possible because the customer charges are a small component of non-residential customer bills. The Staff supported the ultimate elimination of seasonal differentiation from T&D-only rates due to a lack of underlying cost basis, but stated that this should not occur in the current proceeding because of the likelihood of substantial bill impacts. Finally, Staff opposed the total removal of time of day rates as unsupported by underlying costs, but supported the future examination of simplifying the rates. The Staff advised against altering time of day rates in this proceeding due to bill impact concerns.

The IECG argues that the Commission should adopt a separate standby rate for BHE in this proceeding. Specifically, the IECG proposes the adoption of either of the following two basic approaches contained in Dr. Silkman's testimony. These are: 1) customer pays a monthly demand charge (and energy charge, if applicable) calculated as a percentage of the full requirement rate based on the probability that the standby customer would require service at the time of a monthly peak; and 2) customer does not pay any monthly charges (except for customer charges) unless it takes service at a monthly peak, at which time it would pay the full requirements rate (based on its demand at the time of the peak) for the next 12 months. The IECG argues that the adoption Dr. Silkman's proposal would not violate the Commission's "no losers" test because there would be no resulting increase in T&D rates for BHE's other customers. Additionally, the IECG asserts that 35-A M.R.S.A. § 3209(2), which specifically refers to "standby and backup rates," requires the Commission to establish a separate standby rate in this proceeding.

2. Analysis and Conclusion

We agree with BHE and the Advisory Staff that non-residential customer charges should be moved closer to their marginal costs if this can be

[31] In its testimony, BHE proposed the introduction of a residential customer charge. The Staff responded that such a charge would be unlawful under 35-A M.R.S.A. § 3103, and that it would be poor policy to introduce what could be a controversial and confusing charge concurrent with the initiation of retail access. Recognizing the statutory prohibition, BHE withdrew its request to introduce a residential customer charge.

[32] The Commission articulated the "no losers" principle in the *97-580* Order. *Id.* at 113. Generally, the principle means that no customers total electricity bills should increase at the beginning of retail access as a result of rate design changes.

accomplished without violating the "no losers" principle set forth in the *97-580* proceeding. We concur with Staff that it is likely that such movement could occur without negative bill impacts because of the relative size of customer charges compared to total bills. In Phase II, BHE should file its proposed changes to the customer charges and appropriate bill impact analyses, including a bill frequency analysis comparing T&D rates based on the existing customer charges with those reflecting BHE's proposed customer charges.

In our Order in the 97-580 proceeding, we agreed with CMP's general proposition that seasonally differentiated rates appear to lack a sufficient cost basis for a T&D utility, but that time of day rates should be maintained because that rate structure properly reflects the underlying costs of the T&D system. We also concurred with CMP's proposal that time of day rates should be simplified. *Id.* at 123. We see no reason to deviate from these conclusions with respect to BHE. Because of the potential for substantial bill impacts, we will not consider removing the seasonal differentiation in this proceeding. BHE may, however, propose the removal of the shoulder rate if it can demonstrate in its Phase II filing that such action will not cause an increase in customers' March 2000 total rates relative to current rates.

For the same reasons as explained in the 97-580 Order, we decline the IECG's proposal that a separate standby rate be adopted in this proceeding. *Id.* at 145-146. A great variety of standby rate proposals were presented in the CMP proceeding; some would increase the amount generators currently pay, while others would reduce the current amounts paid to the utility. The issues surrounding the development of standby rates were among the most complex and controversial in the CMP proceeding. To avoid rate design "losers," we declined to adopt any of the separate standby rate proposals and directed that standby customers essentially take service under the same rate structure they would today; for most customers this is the all requirements rates corresponding to the customer's size and voltage level of service.[33] We make the same decision here for the same reasons.[34] We disagree with the IECG's argument that, since other rates remain the same, there can be no losers from the adoption of a separate standby rate. The problem is that other rates would not remain the same. If the standby rates reduce the amounts generators are currently paying, other customers would make up the difference through higher rates. If the standby rate would increase the amount generators pay for service over that which is currently paid, then the standby customers would become "losers." It is either of these results that we intend to avoid concurrent with retail access.

[33] Standby customers will be subject to a ratchet, while the ratchet will be eliminated for all requirements customers.

[34] BHE has not proposed to eliminate the ratchet in its rates, so the rates paid by BHE standby customers will remain the same as all requirements customers.

We disagree with the IECG's assertion that 35-A M.R.S.A. § 3209(2) requires us to set a separately denominated standby rate in this proceeding. This provision states in relevant part:

> the commission shall complete an adjudicatory proceeding . . . for the design of cost recovery for transmission and distribution costs, stranded costs and other costs recovered pursuant to this chapter and for the design of rates for backup or standby service.

Section 3209 is part of the State's comprehensive restructuring legislation. Among the numerous tasks necessary to implement industry restructuring, the Legislature directed the Commission to establish revenue requirements and rates for the new T&D-only utilities. In doing so, the Legislature specified that the T&D rates must include rates for standby service. The legislation, however, did not require the adoption of a separate standby rate. Consistent with the legislation, we are adopting rates for standby service in this proceeding. For the reasons stated above, these rates are the same as those for all-requirements customers. We emphasize, however, that although standby customers will pay the same "rate" as all-requirements customers, their "costs" will be substantially less than that for all-requirements service. This is because a substantial amount of stranded costs and fixed T&D costs are included in the energy charge, and the demand charge and ratchet are only triggered when service is taken during an on-peak, winter period.

C. <u>Future Examination of Costs and Rates</u>

Recognizing that a comprehensive rate re-design will not occur in this case, the IECG requests that the Commission set a date certain for implementing a new rate design for BHE. Specifically, the IECG suggests January 1, 2001 as the date certain. The IECG supports its request by noting that a rate re-design has not occurred for BHE for ten years and, thus, rates do not bear a relationship to underlying costs. BHE agrees that a comprehensive rate design is overdue and supports a plan for the examination of rate design in the near future. The OPA, however, states that the Commission should allow 2 years before considering changes in rate design.

In our Order in *97-580*, we indicated that we would review revenue requirements, rate design and a rate plan after having an opportunity to consider experience gained both in Maine and elsewhere with the T&D utility cost structures in a restructured environment. *Id.* at iii, 116,124. We stated that we would undertake this review prior to March 2002. Although we continue to believe that there is a significant value to gathering experience in the new industry environment, we acknowledge as valid the IECG's view that a comprehensive examination of BHE's underlying cost structure and rate design is overdue.

We cannot, however, provide the IECG with a date certain at this time. There is still a great amount of work to be accomplished to implement restructuring prior to March 2000, and it is difficult to predict the magnitude of the effort that will continue after retail access begins. We will also have to begin work on metering and billing competition early in 2000. Additionally, CMP has proposed a 7-year rate plan and the IECG has stated that a comprehensive rate design proceeding for CMP should occur either prior to or concurrently with the processing of the rate plan. Under these circumstances, it is desirable for the Commission to develop a comprehensive plan as to how it will proceed over the first 2 years after restructuring. Such a plan would be similar to the work plan developed to handle the numerous proceedings the Commission was required to conduct to implement restructuring. Similar to the restructuring plan, the post-2000 plan would be developed with the input of the parties and would provide a workable and orderly framework for proceeding into the future. Although it would not be appropriate to commit to a date certain for a BHE rate design proceeding without considering other priorities, we will commit to developing a plan with the input of all interested parties early in 2000. In developing the plan, completing a rate design proceeding for BHE by year end 2001 will be a high priority.

VI. UPDATES

In CMP's "mega-case" proceeding, we recognized, given the complexity of the issues and the need to commence the proceeding nearly two and one-half years prior to the time that new rates would be in effect, that it would be necessary to conduct a fairly extensive Phase II update proceeding. *97-580,* Order at 63. While we will conduct a Phase II proceeding here, we do not expect this proceeding to be nearly as extensive as the one currently being conducted for CMP.

There are several reasons why we believe the need for updating is much less in this case than it was in *97-580.* First, this case was commenced almost a year after we began *97-580* and, therefore, the Company was able to use a more recent test year. Second, the Company was given an opportunity to file a comprehensive update to its case in May of this year. This updated case was further revised by the Company as part of its surrebuttal case. Third, this case is being completed only four months prior to the date that new rates will take effect while the record CMP's Phase I case closed almost a year and one-half before new rates would take effect.

As part of its Case Management Memo, the Company proposed an update mechanism whereby it would submit an exhibit with its reply brief which reflected actual updates for the following topics:

- The extent to which PERC warrants have been exercised;
- The replacement power costs for the divested assets;
- The results of the PUC Order on deferral of restructuring costs;
- Any changes in the underlying assumptions on the interim asset sale savings;
- Any new special rate contracts with customers;
- Reimbursement by the federal government of ice storm costs;
- Low income deferral;
- Maine Yankee expenses;
- DSM expenses;
- Employee transition costs;
- Updated labor-related costs;
- Net revenue from competitive suppliers;
- Net revenue from the sale of natural gas right-of-way easements.

The Examiners could then incorporate the results of the Company's update in the Examiner's Report. Finally, the parties could then comment on updates in their exceptions.

The Examiner rejected this suggested approach since it did not give adequate process to the parties. The Examiner instead asked the parties to address what issues should be updated in their briefs. Despite this request, no briefing has been submitted on the subject of updating.

As part of this Order, we have identified several matters which will require updating. We will allow the parties to suggest other topics for updating at a case conference to be held in early November. After this conference, we will issue a supplemental order which defines the exact scope of Phase II.

VII. CONCLUSION

In this Order, we have resolved to a great extent the methodological issues involved in setting Bangor Hydro-Electric Company's revenue requirements, stranded costs and rate design at the start of retail access. As we have noted, some items must be updated in a Phase II proceeding. BHE is directed to make a Phase II filing consistent with the findings and conclusions contained in this Order. The Examiners in this matter will soon issue a Procedural Order which will schedule a conference of counsel to discuss, among other things, the timing and contents of BHE's Phase II filing. At the conclusion of Phase II, we will establish the actual amounts authorized for revenue requirements and stranded cost recovery and set rates for BHE to be effective March 1, 2000.

Dated at Augusta, Maine, this 24th day of November, 1999.

BY ORDER OF THE COMMISSION

Dennis L. Keschl
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Nugent
Diamond

THIS DOCUMENT HAS BEEN DESIGNATED FOR PUBLICATION

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S.A. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 1004 of the Commission's Rules of Practice and Procedure (65-407 C.M.R.110) within 20 days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within 30 days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S.A. § 1320(1)-(4) and the Maine Rules of Civil Procedure, Rule 73, et seq.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S.A. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.